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February 8, 2010

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*Vice President*
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The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0273 – Feed-in Tariff ("FIT") Proceeding
HECO Companies Report on Reliability Standards

Pursuant to the Commission's September 25, 2009 Decision and Order ("Decision and Order") and October 29, 2009 Order Setting Schedule in the above-subject proceeding, Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited (collectively the "Hawaiian Electric Companies"), respectfully submit for Commission consideration the following report on the development of reliability standards for the Hawaiian Electric Companies' Feed-In Tariff program.

Sincerely,

Attachments

c: Service List

# Proposed FIT Reliability Standards for the Hawaiian Electric Companies

## I. INTRODUCTION

Pursuant to the Commission's September 25, 2009 Decision and Order ("Decision and Order") and October 29, 2009 Order Setting Schedule in the above-subject proceeding, Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively the "Hawaiian Electric Companies" or "Companies"), have jointly developed the following report on the development of reliability standards for the Hawaiian Electric Companies' Feed-In Tariff ("FIT") program ("FIT Program")

### A. Reliability Standards Directives

Through its Decision and Order, the Commission directed the Hawaiian Electric Companies "*to develop reliability standards for each company, which should define most circumstances in which FIT projects can or cannot be incorporated on each island.*" (Decision and Order at 50) The Commission stated that "*in particular*" it wanted the Companies to adopt standards that "*establish when additional renewable energy can or cannot be added on an island or region therein <u>without markedly increasing curtailment, either for existing or new renewable projects</u>.*" (Decision and Order at 50-51) (Emphasis supplied). This is consistent with the Commission's comprehensive guidance earlier in the Decision and Order reminding the Hawaiian Electric Companies of their "*continuing <u>obligation to ensure system reliability</u>,*" "*<u>obligation to refuse to interconnect projects that will substantially compromise reliability</u> or result in an unreasonable cost to ratepayers,*" and discretion <u>not</u> to interconnect projects that would "*likely <u>face significant curtailment or cause significant curtailment for existing renewable energy generators</u>.*" (Decision and Order at 44) (Emphasis supplied)

The Commission emphasized these directives at page 56 of the Decision and Order where the Commission stated unequivocally that based on reliability standards or interconnection studies, the Companies "*<u>must reject</u> projects that substantially compromise reliability*" and "*<u>must not interconnect</u> projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers or would lead to significant curtailment of new or existing renewable energy generators.*" (Decision and Order at 56) (Emphasis supplied) It is against this body of directives and developmental guidance from the Commission that the Hawaiian Electric Companies' reliability standards were developed.

### B. Development of the Standards

In its discussion of the reliability issue, the Commission cited to the briefs of the Hawaiian Electric Companies and State Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate") and the Department of

Business, Economic Development, and Tourism ("DBEDT"). In particular, the Commission referenced the Companies' and Consumer Advocate's statements as to why it is "*difficult to provide a specific number or numbers as to the amount of a particular type of resource a particular grid can accept*" and that it may be more prudent to "*conduct the appropriate evaluations necessary to determine what those amounts could be given reasonable assumptions that can be made.*" (Decision and Order at 47-48) The Commission further cited to DBEDT's recommendation that the Hawaiian Electric Companies "*commission a third-party study of each island's grid (Maui, Big Island, Oahu) to determine how much renewable power the current system can accept....*" (Decision and Order at 48) Recognizing that some parties disputed the utilities' assertions, the Commission nevertheless found that "*reliability constraints exist and could affect the amount, type, and location of renewable energy that can be incorporated into the HECO Companies' systems without compromising reliability.*" (Decision and Order at 49) As stated above, the Commission concluded this discussion by directing the Hawaiian Electric Companies to develop reliability standards "*which should define most circumstances in which FIT projects can or cannot be incorporated on each island*" in part so developers would be able to "*gauge the probability that their projects could be developed.*" (Decision and Order at 50)

Accordingly, in developing their reliability standards, the Hawaiian Electric Companies endeavored to develop standards which would: (1) define the circumstances in which FIT projects can or cannot be incorporated on each island without markedly increasing curtailment, either for existing or new renewable projects; (2) allow the utilities to maintain system reliability; (3) avoid unreasonable costs to ratepayers; and (4) allow a developer of a renewable energy project to be able to gauge the probability that its project could be developed on a particular grid system.

During the development of the Companies' reliability standards, there were discussions, both internal and with stakeholders, regarding whether reliability standards such as those adopted by the North American Electric Reliability Corporation ("NERC") for the Bulk Electric Systems of North America would be sufficient.[1] It was determined,

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[1] The NERC reliability standards define the reliability requirements for planning and operating the North American bulk power system. These standards are guided by reliability principles. Adherence to the reliability principles can be demonstrated and facilitated by the standards, which provide specific guidelines for planning and operation of the power system and also provide measures of compliance. The HECO Companies currently plan and operate their systems in accordance with reliability principles that are very much aligned with the NERC reliability principles. These core reliability principles include:

1. The systems shall be planned and operated in a manner to perform reliably under normal and abnormal conditions
2. The frequency and voltage of the systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand
3. Information necessary for the planning and operation of the interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably

consistent with the Commission's recognition that "*simple metrics might not fully capture reliability considerations*," that more was needed in order to comply with the directives noted above. (Decision and Order at 50) Specifically, simple metrics[2] would not necessarily allow a developer to be able to gauge the probability that its proposed project could be interconnected to a particular grid system (i.e., that there is "room" on a particular system) absent a project specific evaluation against all of the reliability criteria. Consequently, the Hawaiian Electric Companies undertook to conduct the necessary system reviews to determine the amounts of renewable generation that could likely be integrated on each island. The methodologies used to conduct the system reviews and the results of those evaluations are discussed in detail below.

C. Preliminary Determinations and Impacts

Through the Decision and Order, the Commission established initial caps on the FIT Program equivalent to 5% of the peak demand for each of the Hawaiian Electric Companies based upon the cumulative nameplate capacity of the FIT projects on each island. (Decision and Order at 55) In establishing these preliminary caps however, the Commission made clear that the "*caps are not mandates, but maximum levels for FIT participation*" and that "*for reliability reasons, it might not be possible to reach all caps.*" (Decision and Order at 56) As discussed above with regard to this issue, the Commission also mandated that "*the utility must not interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers or would lead to significant curtailment of new or existing renewable energy generators.*" (Id.) (Emphasis supplied)

While the system studies were undertaken in part to determine the extent to which FIT resources could be accommodated on each island, the studies by definition examined the ability of each system to accept new generation resources regardless of

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4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented
5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of the power systems
6. The reliability of the power systems shall be assessed, monitored, and maintained routinely for each power system
7. Bulk Power Systems shall be protected from physical or cyber attacks

However, being island systems as opposed to a large interconnected grid, different operational measures apply. Accordingly, the potential impacts of generation facilitated through the FIT Program on these core reliability principles must be assessed through the studies and evaluations referenced herein. Please see, http://www.nerc.com/files/Reliability_Standards_Complete_Set_2010Jan25.pdf

[2] The HECO Companies do operate their systems according to standard operating criteria. See Table 8 of this report.

procurement mechanism.[3] It is only through the examination of the total system that appropriate determinations can be made as to whether new resources could substantially compromise reliability or lead to significant curtailment of new or existing renewable energy generators.

The system studies and evaluations discussed herein generally indicate that at least for the time being, there is sufficient room on the Hawaiian Electric Oahu distribution[4] system to accommodate the new FIT program in addition to distributed generation[5] ("DG") that may be developed via other mechanisms including net energy metering ("NEM"). The preliminary Oahu studies indicate that no significant system wide reliability or curtailment issues are expected for a distribution system-wide DG penetration level of 60 MW, and further studies are being done to confirm the ability to interconnect more DG beyond this level. Due primarily to the high level of existing and planned renewable resource penetration on the MECO and HELCO systems, the studies indicate that there is minimal to no room at this time to accommodate additional renewable resources (FIT or otherwise) without significant curtailment of either existing or planned renewable resources, or a threat to system reliability.[6] The impact of this determination is that the integration of FIT resources on the HELCO and MECO systems may have to be temporarily deferred until additional studies can be performed and/or infrastructure developed, so that additional distributed renewable generation can be integrated on these systems without threatening system reliability or causing significant curtailment of other renewable generation.

As a part of the concerted effort to evaluate and determine the additional levels of distributed generation resources that can be integrated to each island grid, the Hawaiian Electric Companies support convening a Reliability Standards Working Group that would serve as an open and transparent forum to allow stakeholders and technical experts an opportunity to regularly review and provide input to the studies that are described in this report and the attachments thereto. The Companies recommend that the Reliability Standards Working Group not be restricted to the FIT parties but include representatives with a range of technical expertise (e.g., the United States Department

[3] As one example of the integrated nature of system planning , current Net Energy Metering (NEM) commitments for HELCO and MECO are 3% of system peak demand. Decisions on whether to increase this commitment should be dependent in part upon the system's ability to take on additional distribution level variable generation.

[4] "Distribution system" or "distribution level" as used in this document refers to the HECO Companies' electric distribution systems of 12 kilovolts and below.

[5] "Distributed generation" as used in this document refers to any generating resources interconnected and operated in parallel to the distribution system, including both firm and variable generating technologies.

[6] This is consistent with the Commission's general expression of concern with regard to the HELCO and MECO grids *"which are much smaller and have considerable renewable penetration, compared to the HECO system."* (Decision and Order at 43)

of Energy, Electric Power Research Institute ("EPRI") and the Hawaii Natural Energy Institute). This process would involve collaboration with the Working Group members to establish a framework and processes for the conduct of the studies and the identification of technical solutions. Importantly, as this process will be ongoing and require some level of flexibility to respond to changing system conditions, the Working Group process should be organized and facilitated separately from the Companies' Clean Energy Scenario Planning process.

D. Standards Modification and Accommodation of Resources

Recognizing that the standards should not be static, the Commission expressly directed that standards should be "*flexible, based on experience and changes in system conditions.*" (Decision and Order at 51) Specifically, the Commission asked that the Hawaiian Electric Companies "*modify the standards for each company after each year of the FIT'S operation, or more frequently if appropriate, to reflect changes to transmission, distribution, generation, demand, generation mix, ancillary services availability, the results of ongoing studies, and any other relevant factors.*" (Id.) The Hawaiian Electric Companies are committed to this process and, as discussed below, have presented detailed proposals to examine what will be required to accommodate higher levels of penetration of variable renewable generation on each island system. As demand grows, appropriate mitigating measures through technological solutions (on the power system or interconnecting facilities) and/or system enhancements are identified, approved and completed, and as the generation mix on each island changes to accommodate higher levels of intermittent resources (through the addition of firm, dispatchable, renewable generation), or to the extent that planned renewable additions do not come on-line as anticipated, the Companies will revise and update the standards to allow for the interconnection of additional renewable and FIT generation.

## II. DISCUSSION

### A. The Hawaiian Electric Companies Have Some Of The World's Highest Levels Of Renewable Energy Penetration And Due To The Fact That They Are Island Grids, Encounter Reliability Concerns That Few Other Grids Do.

In previous proceedings, such as the Recovery of Big Wind Implementation Studies Costs through the Renewable Energy Infrastructure Program Surcharge in Docket No. 2009-0162, the Hawaiian Electric Companies have described the HELCO and MECO (Maui) systems and level of renewable penetration achieved on both those island grids. By both national and international standards, the State of Hawaii is a leading integrator of renewable technologies with renewable generation penetration levels close to 40% on both the HELCO and MECO grids.[7] A significant portion of this

[7] HELCO with 39% and MECO with 38% (Max Wind Power/Min Load + Export Capacity (MW)) are behind only West Denmark (58%), Schleswig Holstein (Germany)(44%), and Gotland (Sweden)(40%). Source (other than HELCO and MECO) "Wind Power Integration in EirGrid

energy is in the form of variable wind power.[8] Given their size and unique geographic location, the island grids operated by HELCO and MECO have achieved remarkable renewable penetration levels as cited by the Solar Electric Power Association.[9] Conversely, to manage such levels, each of the island grids have had to take measures to ensure operability and reliability of their systems through modification of operating procedures, changes to the supplementary system balancing and control process, generator modifications, and by enforcing conditions such as curtailments and other management measures identified by interconnection and system integration studies.

With its high renewable resource penetration levels the HELCO system provides a case study for island systems on issues that can occur with high penetrations of distributed generation relative to overall system size. In addition to the issues that arise with distributed generation generally, additional issues arise when much of the new generation is or will be coming from variable photovoltaic ("PV") resources. HELCO already has a very high amount of variable generation from run-of river hydroelectric and as-available wind resources on its transmission system, which creates issues and uncertainties for real-time balancing and frequency control. The impact of variability from the distributed PV is further complicated by the fact that the typical capacity factors, production profile, degree of variability and correlation between sites is not known and there is nearly no visibility or controllability of production (either by the facilities or by the utility) from these sites for the system operator. With these high levels of DG penetration on the HELCO system, which are expected soon on the MECO system, significant dynamic stability effects on the power system are already being encountered. These issues are more complicated to analyze than steady-state effects and require targeted studies to address specific system impacts.

To date, very few mainland grids, which typically drive the setting of new industry standards, have exhibited the same system dynamic issues currently being experienced on the HELCO system. For the North American interconnected utilities, the issues are for the most part theoretical, as penetration levels remain small relative to the overall interconnection. Presently, DG impacts on the North American interconnections are primarily steady-state (effects on the power flows and voltages), particularly for systems such as the Electric Reliability Council of Texas (ERCOT)[10] where the system is already constrained by other generation (such as wind). Although not directly comparable with an isolated system, for smaller municipal utilities like the Sacramento Municipal Utility District ("SMUD") in California, which have comparatively high levels of distributed

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Operating Experience", Jody Dillon, Renewables Integration Group, presented at the UWIG conference in Fort Worth, Texas, April 2008.

8 HELCO's energy production for the month of February 2009 included 14.3% coming from wind.

9 See, http://www.solarelectricpower.org/media/84522/sepa%20top%20ten%202009.pdf

10 Texas maintains a separate grid from the rest of the Eastern and Western United States interconnections.

generating resources on their system, dynamic system balancing and controls impacts are primary issues of concern with the introduction of advanced metering infrastructure ("AMI"), Smart Grid communities and California Solar initiatives policies. The key difference between the isolated island systems and mainland interconnected systems is that the isolated Hawaii grids will experience imbalance in the form of frequency error and a change in generation mix will have more profound impacts on dynamic stability.

Steady-state and dynamic impacts are further exacerbated by the fact that planning of the distribution system has historically been somewhat isolated from transmission system planning for most power systems. This is especially true on the mainland where integration studies have been conducted at the ISO/Balancing Authority system level concentrating on congestion impacts on the larger transmission network and connections between states and have not addressed the dynamic issues resulting from distribution system impacts which are currently the responsibility of the individual operating utility companies. SMUD and the Hawaiian Electric Companies have teamed as utilities to address these emerging issues tying the transmission and distribution impacts on the SMUD system with lessons learned on the Hawaii systems. Recently, the SMUD and Hawaiian Electric Companies' proposal to the California Public Utility Commission to conduct a joint monitoring and investigation study related to high-penetration of PV resources received a $2.9M award and was publicly acknowledged with the highest rank score for all the proposals received. A number of the issues and proposed mitigation strategies to be addressed in this California/Hawaii partnership are identified based on observed system impacts on the HELCO system.

B. <u>To Determine The Levels Of Additional Variable Generation That May Be Integrated On An Island System, The Entire System Must Be Evaluated</u>.

Until recently, power systems have been managed centrally with power flowing from the generation resource through the transmission and distribution systems to customer load. It has only recently been the case that DG sources, such as those encouraged by mechanisms such as the FIT and NEM programs, have changed this uni-directional power flow by connecting generating resources to the distribution system. When a generating source is connected to the distribution system, any excess power not consumed in the local distribution circuit is exported onto the sub-transmission or transmission systems. Consequently, there are reliability considerations that must be studied to protect the customers on the circuit to which distributed generation is connected from negative impacts.

As the amount of DG is increased on a power system, the effect of the DG upon the entire power system must be assessed, in addition to the effects upon the distribution circuit. There may be reliability benefits for certain applications of DG, which are specific to the characteristics of the location, type of DG, and power system to which the generator is interconnected. There are also potentially negative reliability impacts from DG, particularly for high levels of DG relative to the circuit and/or system demand.

For the existing levels of distributed and variable generation on the HELCO and MECO systems, and the projected levels of distributed and variable generation levels on the Hawaiian Electric system, the effect of the DG also needs to be considered on an aggregated system level. A unique aspect of this consideration for island systems is the effect upon the power system dynamics, including the ability to maintain operations through faults and contingencies. For example, if a large amount of generation is present on a circuit (relative to the demand on the circuit), distribution level problems are encountered as the distribution level protection schemes are not designed to push generation back onto the grid. Power quality issues can arise if the circuit opens for a fault, and anti-islanding schemes will be required at higher penetration levels. Also if local generation exceeds the local load at the feeder, the excess energy may cause congestion or other operational problems at the larger system transmission level. By managing the level of non-dispatchable DG at the distribution feeder to a proportional amount of the total feeder load and maintaining balance with other local distributed resources on the feeder, problems of power quality on the circuit relating to possible islanding can be minimized. However, even if each feeder penetration is small, having a large amount of DG resources on the power system in the aggregate can have very significant consequences to the power system as a whole. The consequences occur through a combination of factors, including but not limited to:

- Variability of the DG, which can negatively affect system balancing and frequency control;,
- Lack of visibility and control of the DG by the utility system operator, resulting in greater uncertainties in power balancing and inability to manage the distributed resources during system restoration or for frequency control;
- Displacement of production from transmission-side resources which contributes to excess energy problems including curtailment, and may displace energy production by renewable providers with better cost performance and system benefits; and
- Other characteristics of the distributed resources including behavior during faults and contingencies.

As renewable penetration continues to increase with variable renewable generation resources interconnected at the transmission and distribution levels, a more integrated process of evaluating distribution level impacts on system performance is critical, especially when potential bi-direction flow of electricity may be encountered or when the aggregate amount of distributed generation becomes a significant portion of the production on the power system. This has become very apparent on the HELCO system where present levels of distributed resources are causing system issues which negatively impact reliability. Without implementing measures to further address the overall impacts to system reliability for all the island systems, and particularly for Maui, Molokai, Lanai and the Big Island of Hawaii, additional distributed resources that are coming online have a high likelihood of causing adverse reliability impacts.

C. <u>Sound Electrical Planning, Operating Practices, And Engineering Guidelines Derived From Operating Experience And Engineering Studies</u>

<u>Should Form The Basis For The Development Of Existing System Baselines And To Quantify The Impact Of Increasing Renewables On The Systems</u>.

The ability of a utility to cost-effectively balance supply and demand is a critical measure of system reliability. Operators must constantly balance generation supply to meet demand and reserves for contingency requirements. As impacts are observed, follow-on system and local level studies must be performed to assess baselines and recommend corrective action or measures to ensure overall system reliability. As planning and scheduling are based on system maximums and operations are based on real-time response to conditions, the methodology to evaluate system reliability must consider both steady state and dynamic system impacts. For purposes of quantifying reliability on the island grid systems, steady-state excess energy (curtailment) impacts and dynamic system frequency issues are proposed as initial measures to establish existing system baselines and to quantify the impact of increasing renewables on the systems. Consequently, Reliability Standards, as defined by the Hawaiian Electric Companies, are established principles that govern the planning and operation of the electrical system to maintain the delivery of reliable power from generator to load. Sound electrical planning, operating practices, and engineering guidelines derived from operating experience and engineering studies are the basis for the development and application of such principles which are set forth and described in Figure 1:

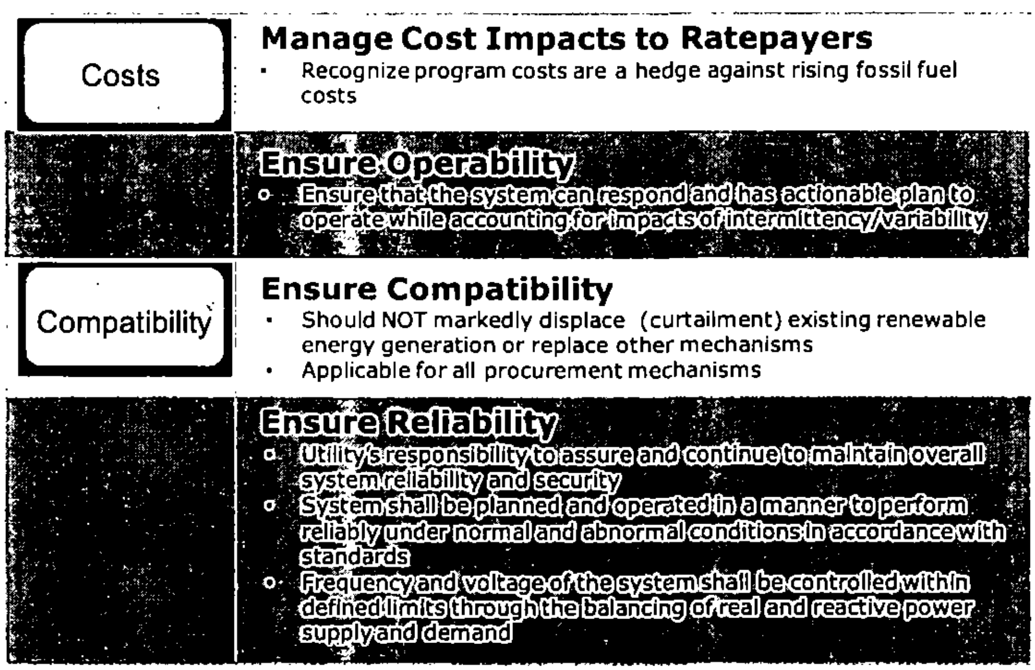


Figure 1. Proposed Reliability Standards/Principles for Aligning Operating Criteria and Shaping System Studies.

System operating criteria and actions can be aligned to each of the reliability principles ("Principles") to evaluate system integrity, operability and economics.

However, the operating criteria alone do not establish the limits upon the level of additional distributed renewable energy that each system can integrate. Rather, the system operating criteria must be tailored for each system based upon their unique portfolio of generating resources. As an example, on the HELCO system, considerable base loaded geothermal production has displaced conventional generation, with additional biomass and geothermal resources planned within the next two years. Additionally, both HELCO and MECO have a significant amount of fast starting units on their systems, whereas Hawaiian Electric, with its larger steam generation units on Oahu, does not have the same fast starting capabilities or contingency reserve policies.

For the islands of Molokai and Lanai, the operational criteria and practices are different than on the Oahu, Maui or Hawaii island grids due to the size of the load on those smaller islands and the fact that, in effect, the two smaller islands are served only by a distribution system. As the system demand on Molokai and Lanai is much smaller in comparison to the other islands, system balancing and frequency control is accomplished by generating units operating in isochronous (zero droop) mode. In this scheme, the isochronous generation automatically responds to any change in frequency with a change in its output in order to maintain a constant frequency. This frequency control scheme is common for small electrical systems with a few generators. A system being managed through isochronous control will maintain a very constant frequency unless an imbalance occurs at a rate of change faster than the ramping capability of the isochronous generation, or the imbalance exceeds the operating range of the isochronous unit (driving it to maximum or minimum output). In isochronous mode, one generator (or coordinated bank of generators acting in concert) regulates the system frequency. The other generators connected to the grid may be set with a typical governor droop but the isochronous unit provides the means for stable grid frequency control to the target frequency. In such a system, the increase and decrease of the non-isochronous units must be managed in order to maintain regulating capacity on the isochronous generation, rather than on economic dispatch. No two units can operate in isochronous mode as they will compete for control to set the speed or frequency of the system.

For larger multi-generation systems, no single unit sets the system frequency and all operate in droop mode to help preserve system frequency. The supplemental control to restore system frequency is provided by the Automatic Generation Control ("AGC") system. A central system operator assisted by AGC manages changes on the system in response to load changes, which is done with the dual purpose of managing system frequency and allocating load among controllable generators to minimize production cost through economic dispatch. As penetration levels of renewable resources continue to increase, additional studies are required to address the load management capability on the Molokai and Lanai systems, and the conventional methodology for system balancing and frequency control through AGC employed on the Maui, Oahu and Hawaii island systems may no longer be feasible.

D. <u>Establishing The Baseline – The Island Systems Today</u>

In order to determine what additional distributed resources can be integrated onto each island system without impacting reliability, it is necessary to determine the current levels of DG resources on each grid. Accordingly, for each of the islands, an initial inventory of distributed resources interconnected at the distribution level was conducted for purposes of developing a system baseline of resources. Summaries for each of the island grids and present baselines as of the end of 2009 are shown in Table 1. The detailed analysis in support of this summary table is discussed below.

Table 1. Summary of Interconnected Distribution Level Penetration on Each Island Grid.

| Island Grid | Net System Load at Peak (MW) | Existing Distribution Level Penetration on System (MW) | Existing Distribution Level Penetration by % of Peak System Load |
|---|---|---|---|
| Oahu | 1,200 | 40.1 | 3.3% |
| Hawaii | 194.6 | 9.1 | 4.7% |
| Maui | 199.9 | 5.8 | 2.9% |
| Lanai | 4.70 | 2.1 | 43.7% |
| Molokai | 5.95 | 0.3 | 5.0% |

E. Appropriate Studies Were Performed For Each Unique Island Grid To Determine, For Purposes Of The Initial FIT Program (2010-2012), The Approximate Level Of Additional Distributed Generation That Could Reasonably Be Integrated Without Negatively Impacting System Reliability, Ratepayer Cost, Or Curtailment Of Existing Or New Renewable Resources.

As discussed above, the Commission was clear in its Decision and Order that the Hawaiian Electric Companies "*must not* *interconnect projects that will substantially compromise reliability or result in an unreasonable cost to ratepayers or would lead to significant curtailment of new or existing renewable energy generators.*" (Decision and Order at 56) (Emphasis supplied). Stated another way, the interconnection of projects which substantially compromise reliability, result in unreasonable costs to ratepayers or lead to significant curtailment of new or existing renewable energy generators would be contrary to the Commission's Decision and Order. Accordingly, in evaluating and establishing the circumstances in which FIT projects can or cannot be incorporated on each island, the Hawaiian Electric Companies were cognizant of the need not to establish integration levels which conceivably could compromise reliability and instead conducted the appropriate studies to determine integration levels that reasonably assure that reliability could be maintained and resource curtailment managed.

The following is a discussion of the island-specific studies or analyses which were conducted for the purpose of developing reliability standards for each island system.

1. Oahu

As indicated on the following table, which captures known interconnected distributed resources by category, currently, Hawaiian Electric does not have a high level of penetration of distributed renewable resources on its system although that level is anticipated to increase significantly over the course of the next few years due to the FIT Program. All FIT Tier 1 and 2 resources are anticipated to be interconnected to the HECO distribution system, and it is possible that smaller Tier 3 resources may be as well.

Table 2. Existing DG, Oahu

| **HECO Installed DG Summary** As of 12/31/09 | | | |
|---|---|---|---|
| Type of Agreement | Variable DG kW | Non-Variable DG kW | TOTAL |
| NEM and SIA Generation | 9,822 | 300 | 10,122 |
| No Sale | 0 | 30,000 | 0 |
| TOTAL | 9,822 | 300 | 10,122 |
| % of 1200 MW System Peak | 0.82% | 2.52% | 3.34% |

Although it is not at the penetration levels achieved by the neighbor islands, Hawaiian Electric already has several distribution feeders with penetrations approaching 15% (a level at which it is recommended that a study be conducted to evaluate and assess additions to a circuit). Additionally, the Hawaiian Electric power plants were designed to serve base load requirements and economically dispatch to serve customer load. The units were not designed to dispatch and cycle to respond to high penetrations of variable generating renewable resources. Accordingly, if Hawaiian Electric is required to provide spinning reserves for a percentage of any additional variable resources, such as wind and solar facilities, there is a concern that the Company's existing units may not have the ramping capability or fast start up times to support the required spinning reserve requirements. Moreover, Hawaiian Electric is concerned about under frequency, voltage, and other system reliability issues which could arise as a result of any delay in the ramping of units to serve load and result in curtailment of customer load.

In order to assess the ability of the Hawaiian Electric grid to integrate additional levels of distributed renewable resources, Hawaiian Electric retained BEW Engineering ("BEW") to analyze Hawaiian Electric's distribution system and preliminarily determine the level of additional resources that the system might accept without compromising system reliability. BEW's full report is attached hereto as Attachment 1 and highlights some of the potential issues on the existing generating system that must be studied to determine the ability of the generating system to facilitate higher penetrations of renewable resources. The report also recommends further study of distribution system operations and switching routines, as well as the dynamic response of the system through faults and contingencies under future operating scenarios, to ensure that the system remains stable under various operating conditions. Moreover, the report recommends that Hawaiian Electric complete planning and operating studies on its entire transmission, distribution and generating systems to determine the upgrades and modifications needed to support higher penetrations of variable generating resources.

Because BEW recognized that a significant portion of the studies it recommended would not be able to be completed in the time available for the development and submission of reliability standards to the Commission, BEW analyzed examples of both existing feeder loadings and the impact of distributed PV resources upon the system peak load profile to determine the potential for reliability and operating problems with higher penetrations of variable resources. As discussed in Attachment 1, BEW's conclusion is that there is the potential for reliability and operational issues with higher penetrations of variable resources and that to avoid the situations that are occurring on some of the neighbor island systems, it would be prudent and responsible for Hawaiian Electric to establish a reasonable limit on the amount of additional distributed variable generation it can integrate on its grid until additional studies can be completed to fully evaluate the impact of higher levels of penetration on system reliability.

Through its analysis, BEW has established that an initial DG penetration level of 60 MW is deemed feasible, based on high level steady state scenario analysis. Several tens of megawatts more of DG could possibly be accommodated, however additional more refined studies are needed to confirm this. HECO will conduct these studies over the course of the next year, in time to support the next FIT Reliability Standards update.

Given that existing DG on the HECO system is just over 40 MW and given that not all FIT Tier 3 resources will be interconnected at the distribution level, there appears to be adequate space on the HECO distribution system to accommodate FIT and other DG resource additions including from NEM, at least until the FIT Reliability Standards are reviewed within the next year. As discussed in greater detail below, as additional studies and initiatives are undertaken and evaluated, including but not limited to the build out of the infrastructure required to safely integrate higher penetration levels, these limits will be regularly evaluated to determine the extent to which higher levels of distributed resources can be supported and attained.

2. Hawaii Island

The HELCO system, with its high existing penetration of distributed PV, provides a case study for overall system impact issues that can occur at high levels of DG penetration relative to the overall system size. The HELCO system also has individual circuits with up to 62% penetration. In addition to the issues that come with DG in general, much of the generation is variable PV. HELCO already has a very high amount of variable generation from hydroelectric and wind resources on the transmission system, which creates issues and uncertainties for real-time balancing and frequency control. The impact of variability from the distributed PV is complicated by the fact that the typical capacity factors, production profile, degree of variability and correlation between sites is not known and there is nearly no visibility of production from these sites for the system operator. At the levels of DG penetration on the HELCO system significant dynamic stability effects on the power system are encountered, which are more complicated to analyze than steady-state effects.

Table 3 below is the current and forecasted status of DG on the HELCO system as of December 31, 2009. Variable resources are further broken out by under frequency trip setting, that is, at either 59.3 or 57.0 Hz.

Table 3. HELCO DG, Existing and Planned

| **HELCO DG Summary**<br>As of 12/31/09 | | | | | |
|---|---|---|---|---|---|
| Type of Agreement | Variable PV_Wind_River kW @ 59.3 Hz | Variable PV_Wind_River kW @ 57.0 Hz | Variable PV_Wind_River Total (kW) | Non-Variable Diesel_Propane (kW) | TOTAL |
| NEM Generation | 2360.7 | 1077.4 | 3438.1 | | 3,438.1 |
| No Sale | 1860.0 | 1305.0 | 3165.0 | 2345.0 | 5,510.0 |
| Schedule Q | 167.7 | 0.0 | 167.7 | | 167.7 |
| TOTAL Existing | 4388.4 | 2382.4 | 6770.8 | 2345.0 | 9,115.8 |
| | | | | | |
| Planned DG | 145.8 | 7805.0 | 7950.8 | | 7,950.8 |
| TTL Existing & Planned | 4534.2 | 10187.4 | 14721.6 | 2345.0 | 17,066.6 |
| % of 194.6 MW Sys. Peak | % @ 59.3 Hz | % @ 57.0 Hz | % Total Variable | % Non-Variable | % TOTAL |
| Existing | 2.3% | 1.2% | 3.5% | 1.2% | 4.7% |
| Existing & Planned | 2.3% | 5.2% | 7.6% | 1.2% | 8.8% |
| % of 168.2 MW Avg. Day Peak | | | | | |
| Existing | 2.7% | 1.4% | 4.1% | 1.4% | 5.5% |
| Existing & Planned | 2.8% | 6.2% | 8.9% | 1.4% | 10.3% |

HELCO's existing total is 9.1 MW, which comprises 4.7 % of the 2009 system peak of 194.6 MW. However, most DG is PV and therefore is producing during the day peak. Using the average weekly high day peak, the total existing DG is at 5.5%. Further, many more projects are projected for 2010. The table above includes as "planned" DG resources those projects submitted to HELCO for interconnection review as of the end of 2009. Considering both existing DG and these planned DG resources, there would be a total of 17.1 MW of DG, of which nearly 14.4 MW will be PV, with another .36 MW of wind and hydroelectric. The projected additions would take the DG to 8.8% of the system peak, and 10.3% of the average weekly high day peak. Most of the existing and all of the planned DG are variable (non-firm) resources.

Because HELCO recognized that the changing generation mix on its system, due to the anticipated addition of significant DG and addition of large wind resources changed the HELCO power system characteristics, HELCO commissioned a series of system studies to investigate possible impacts of the shift in generation using the consultant Electric Power Systems, Inc (EPS). The first of the studies included an initial assessment of adding large amounts of DG along with variable wind resources and was completed December 19, 2005. In early 2008, as programs such as NEM saw an increase in the anticipated DG penetration on the HELCO system, a task force was created to identify areas of concern and study. The results of those studies are discussed more fully in Attachment 2 to this report, Evaluation of Distributed Generation Resources, and in summary address the fact that as distributed resource penetration levels increase: (1) system protection schemes become more complicated; (2) voltage regulation challenges arise; (3) islanding, grounding and over-voltage issues must be considered; and (4) system level issues must be addressed. Attachment 2 also contains the recommendations and conclusions from the analysis which was performed including suggested modifications to the distribution system necessary to accommodate higher levels of distributed resources, possible required system changes and the recommended system studies to determine the impacts of additional penetration levels.

Additionally, the Evaluation of Distributed Generation Resources discusses the reliability impact of an aggregate loss of distributed generation, and analyzes the impact of distributed generation on the HELCO system during generator contingencies. The Evaluation concludes that HELCO system reliability has been negatively affected by the existing connected DG, as compared to what would have occurred in the absence of the DG. This impact occurs through lower frequency minimums and/or additional load-shed during loss of generation events. This supports the observations of HELCO Operations personnel that load-shedding is occurring for losses of generation that previously did not result in under frequency load-shed. As a result of the findings, HELCO took immediate steps to change the frequency trip settings for existing and anticipated DG projects, where possible. In order to allow more variable generation on the system, HELCO was successful in converting 2.4 MW of variable distributed generation from 59.3 hertz to 57.0 hertz reducing the aggregate variable generation with frequency set-points of 59.3 hertz from 6.8MW to 4.4MW.

Attachment 3 to this report discusses system balancing and frequency control concepts for HELCO although these concepts apply equally to each of the island systems. The evaluation concludes that system frequency control and balancing is challenging on the HELCO system due to the fact that it is a small isolated system with a large number of must-take generating facilities which do not participate in frequency response. The evaluation also determines that the variable output from wind generation on the HELCO system has had a measurable effect on frequency control. While HELCO has taken many actions to mitigate the impacts of the variable wind generation on frequency control, including modification of its AGC program and parameters, variable wind remains the largest driver for frequency error on the HELCO system. It is also discussed that the aggregate loss of distributed generation during faults or generator contingencies is a concern as system trips during low-frequency periods can result in a lower frequency nadir or additional loss of customers; and trips during voltage updates may trigger under frequency load shed where none would otherwise have occurred.

Finally, Attachment 4 evaluates both excess energy and curtailment situations for the HELCO and MECO systems. Based upon straightforward evaluations of a typical day resource stack against daily load curves, such as that illustrated in Figure 2 below, there are periods during which there would be excess energy on the HELCO system, requiring curtailment of renewable energy from new or existing renewable energy facilities. Indeed, the graphs show that during periods of high variable resource output, in the absence of significant load growth, it will be difficult for the HELCO system to accommodate future and existing renewable energy resources even if all dispatchable conventional generation operates nearly twenty four hours a day at near minimum output.

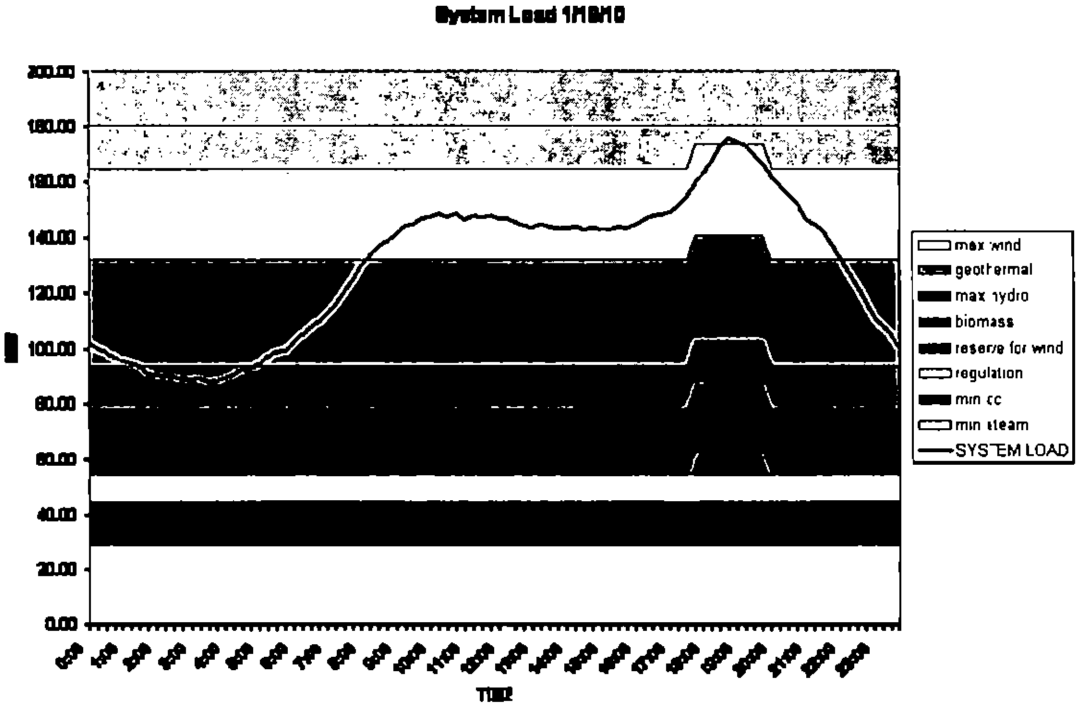


**Figure 2. Present day HELCO net-to-system load curve plotted over 24 hours, plotted against the minimum conventional generation (plus present minimum reserve down) and maximum possible renewable energy. The shaded areas above the dark line indicate periods of excess energy. Note that an additional unit is brought online during the peak period to provide online reserves as hedge against changes in the wind output.**

Figure 2 assumes minimum must-run dispatchable generation plus reserves, maximum output from dispatchable renewable energy sources and maximum variable generation. This output is shown in a stack chart against a typical daily load curve. The graph illustrates the additional curtailments that would be necessary if it is necessary to start up additional generation during the higher peak periods to provide online reserves to cover for the wind uncertainties. The stack areas that are above the load line show periods where there would be excess energy, requiring curtailment of renewable energy from new or existing renewable energy facilities. Operating in this manner could have significant cost implications and may not be prudent due to potential reliability implications. The operating policy for minimum regulating reserve down will need to be reassessed to consider daytime probable load loss events, and the spinning reserve policy may also require reassessment for the future generation mix. Even under periods of moderate variable output, curtailments in the near term seem likely to extend into daytime hours.

As illustrated in Attachment 4, the addition of DG resources has already increased the curtailment of existing renewable energy resources. As the level of variable renewable resources increases, especially smaller resources such as FIT Tier 1 and 2 projects for which installation of curtailment controls are generally not feasible, curtailment of larger resources will begin to occur during day time hours. New variable generators that are large enough to be curtailed, including FIT Tier 3 resources, would themselves be subject to significant curtailment, challenging their project economics. Increasing the renewable energy percentage significantly above that already in place for the HELCO system can occur only if demand is increased or if firm renewable energy is added to the system which can reduce the number of must-run fossil fuel units. Until this can be accomplished, it is apparent that the HELCO system's ability to accommodate additional variable generation is extremely limited, primarily because of the very high penetration of existing variable renewable resources.

As stated earlier, the amount of planned generation as of the end of 2009 would result in a DG penetration level of 8.8% of HELCO's 2009 system peak. HELCO also receives several applications for DG interconnection on a weekly basis, and has received proposals to enter into bi-lateral negotiations for power purchase agreements pertaining to variable DG. Meanwhile, HELCO had earlier committed to performing a system study to determine the basis for a potential request for proposals ("RFP") for variable renewable energy, pursuant to the Commission's December 2006 Framework for Competitive Bidding ("Framework"). This analysis shows that at the current time, HELCO is unable to issue an RFP, and moreover, as additional interconnection of variable generation continues outside of the Framework, via standard interconnection agreements, NEM, and bi-lateral PPAs, the ability to entertain such an RFP further diminishes.

In light of the existing grid constraints and the urgency of the situation, HELCO proposes to defer additional variable DG interconnection requests on the HELCO system, including standard interconnection agreement and NEM requests, until appropriate mitigation measures are identified and employed to appropriately integrate additional variable DG. HELCO also plans to defer entering into bi-lateral PPA negotiations; however, consistent with the Commission's decision and order in the FIT Proceeding, developers may still request, and pay for, additional studies to further assess their project's feasibility. Bi-lateral negotiation cannot be guaranteed, and in fact can only proceed if such additional studies show that projects would not result in significant reliability impacts, significant curtailment of existing or planned renewable generation, or unreasonable costs to ratepayers.

3. Maui

As illustrated in Attachment 4, excess Energy is a condition which exists when the amount of generation being produced on a system exceeds the availability of the system to take the generation. Excess energy exists when the system's must-run units are at their minimum dispatch level, with consideration for down-reserves to respond to typical load loss events and yet the system frequency is high (above 60 Hertz). This indicates that the production exceeds the demand on the system. When production exceeds demand, the system frequency will rise. At this point it is necessary to reduce the production from must-take generation resources in order to balance system production and demand. This condition occurs routinely on the MECO system today, primarily during the off-peak times of day. An example of a 24-hour period with curtailments is provided below in Figure 3.

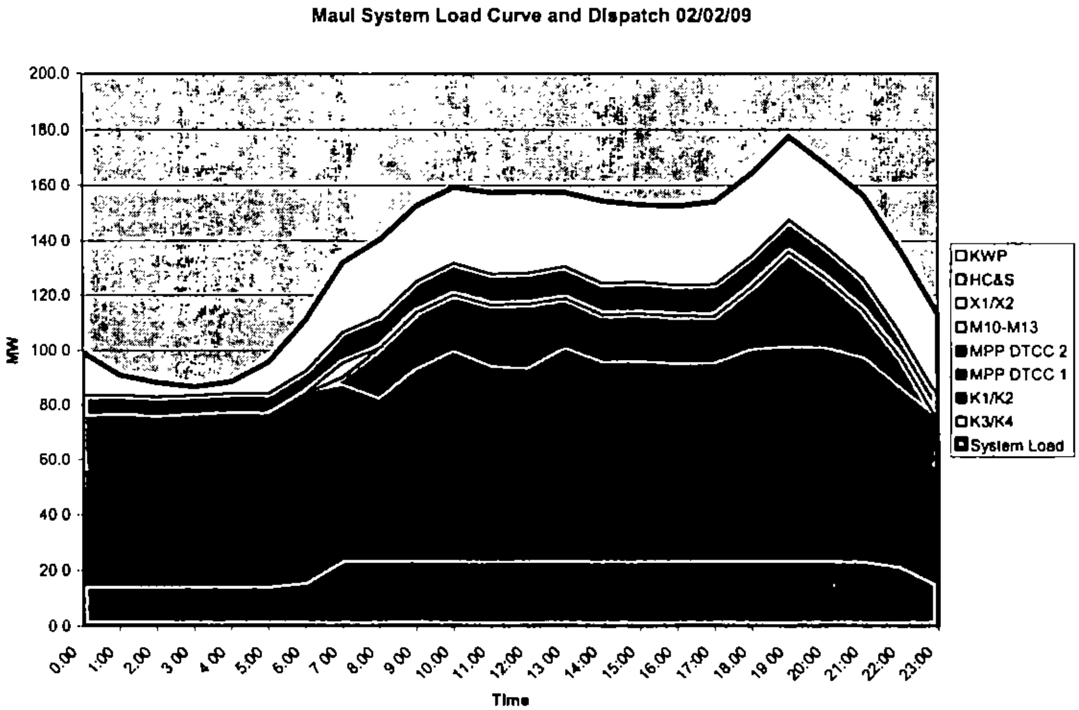


**Figure 3. Maui generation dispatch on 02/02/09. Curtailment of KWP was necessary during lower-demand periods.**

The amount of hours of curtailment will depend on the customer demand, the production from the must-take energy sources, and the mix of must-run units. Figure 3 below illustrates a range of possible hours of curtailment for the present MECO generation mix.

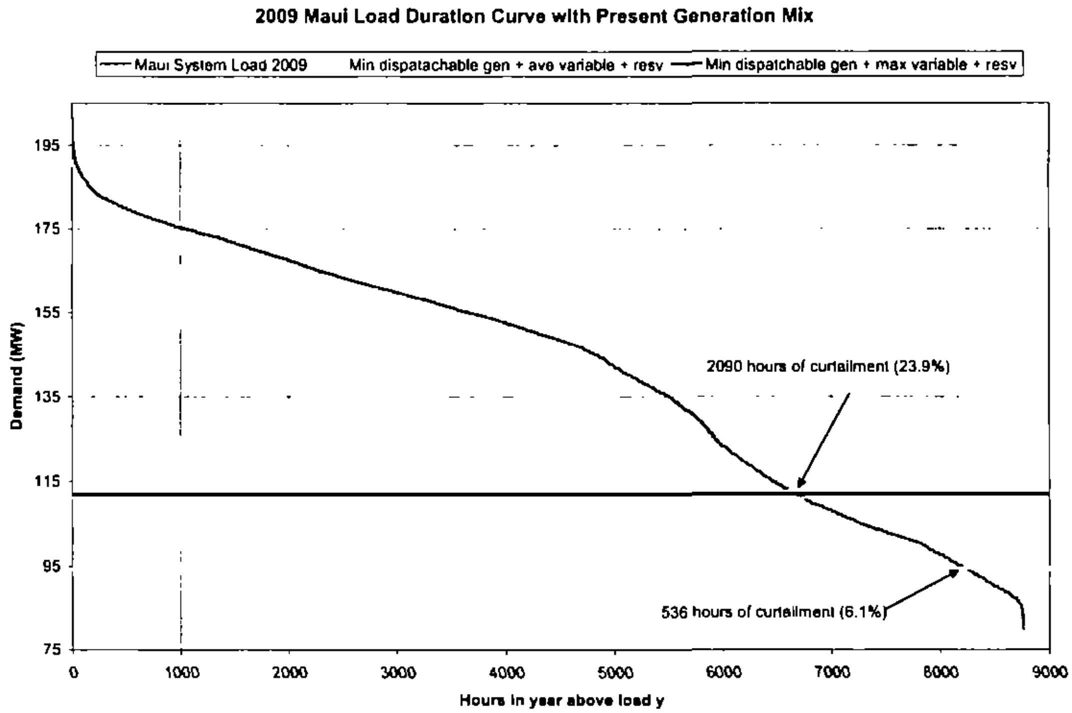


**Figure 4. 2009 Load duration curve illustrating a range of possible hours of curtailment due to excess energy based on average and maximum variable generation and typical must-run generation levels**

Figure 4 is for illustrative purposes, as it assumes the typical minimum must-take generation (including reserves) and maximum dispatchable renewable energy. This does not consider periods where must-run generation and/or dispatchable renewable energy are higher or lower due to operating conditions, derations, or outages. The average variable generation and maximum variable generation are used to illustrate the range of curtailment. The actual curtailments will depend on the correlation of high-production, high capacity factor periods. When the resources are correlated in high output, the curtailment extends into more hours of the day (into higher demand periods). Since curtailment for excess energy typically happens on Maui in the early morning, the minimum dispatchable generation is representative of typical early morning conditions. The output for Makila Hydro, a 500 kW hydroelectric unit, is ignored. For Maui, curtailment can occur from approximately 6 to 24 % of the day. The number of hours of curtailment is significant, as there is more energy being produced than the MECO system can take. The obvious implication of curtailment is that variable renewable energy which is available cannot be utilized on the system.

There are additional implications of operating a system in a curtailment mode as the dispatchable units are operating at near-minimum dispatchable load (slightly above minimum load to provide downward regulating reserve). This impacts generator efficiency, which affects system operating costs; and system frequency response capability, which affects reliability.

There is a significant negative impact on efficiency when running near minimum output on dispatchable units, and consequently, there is a negative impact on cost. The efficiency of units at near minimum load is significantly worse than at near maximum loads. There is also a potential reliability risk operating near minimum output on dispatchable units. The minimum output for each dispatchable unit is determined by the lowest level of stable operation on the generating unit. Operating below this level can result in the unit tripping offline or cause deviations from environmental permit requirements. When all units are near the minimum output, the system is vulnerable to failure for loss-of-load events. The ability of the units to back down for high frequency excursions is limited and the units may be driven offline. The present downward regulating reserve requirement has been set at the minimum regulating reserve down for the single contingency loss of load during minimum load (off-peak) conditions. Loss of more than this amount (6 MW on the MECO system) can drive the responsive units (through their droop response) to below their stable operating point and risk loss of the units, or prolonged high-frequency excursions which may cause trips of other generation and cascading outages. The potential loss of load is larger during daytime conditions. The risks of prolonged operation near minimum loads, and possible adjustment to prudent downward regulating reserve, need to be studied, and operating criteria revised if necessary, considering the future increase of hours under excess energy conditions.

Additionally, MECO has preliminary and/or firm contractual agreements in place for renewable energy additions. Figure 5 illustrates demand vs. available generation for the Maui future generation scenario. The figure assumes: 1) regulating reserve up to cover 50% of the first 30 MW of wind and 100% of any additional wind generation, 2) regulating reserve down is fixed at 6 MW, 3) two additional wind farms of 21 MW each, 4) unit start times and loading schedule are ignored, 5) output from Makila Hydro (500 kW) is ignored. Other than the two new wind farms, all other potential new renewable energy generation (i.e., FIT, bi-lateral PPAs, NEM) is not reflected in the graph.

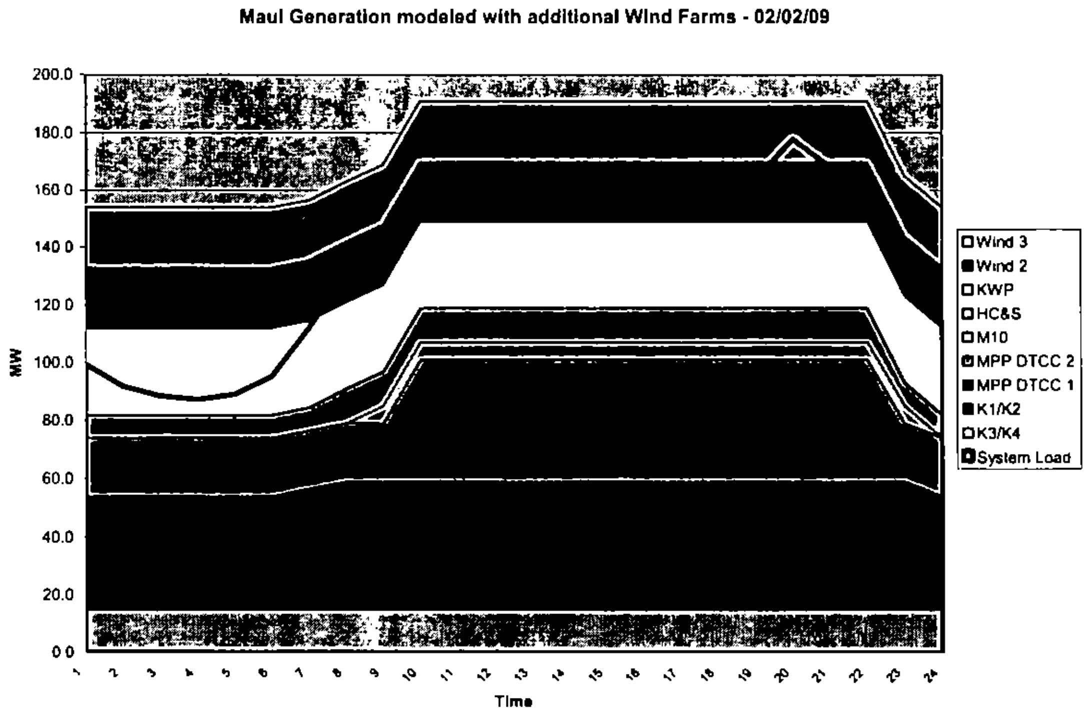


Figure 5. Present day load curve plotted over 24 hours, plotted against the minimum conventional generation (plus regulating reserves) and maximum possible renewable energy for Maui. The shaded areas above the dark line indicate periods of excess energy.

Figure 6 shows a typical daily load profile against the minimum output from the dispatchable generation (including regulating reserves, must run, and must take) and maximum variable generation. The stack areas above the System Load line represent excess energy and would require curtailment. Absent significant load growth, MECO cannot accommodate all the existing or future renewable generation even with conventional generation backed down to minimum (plus down reserve) 24 hours a day.

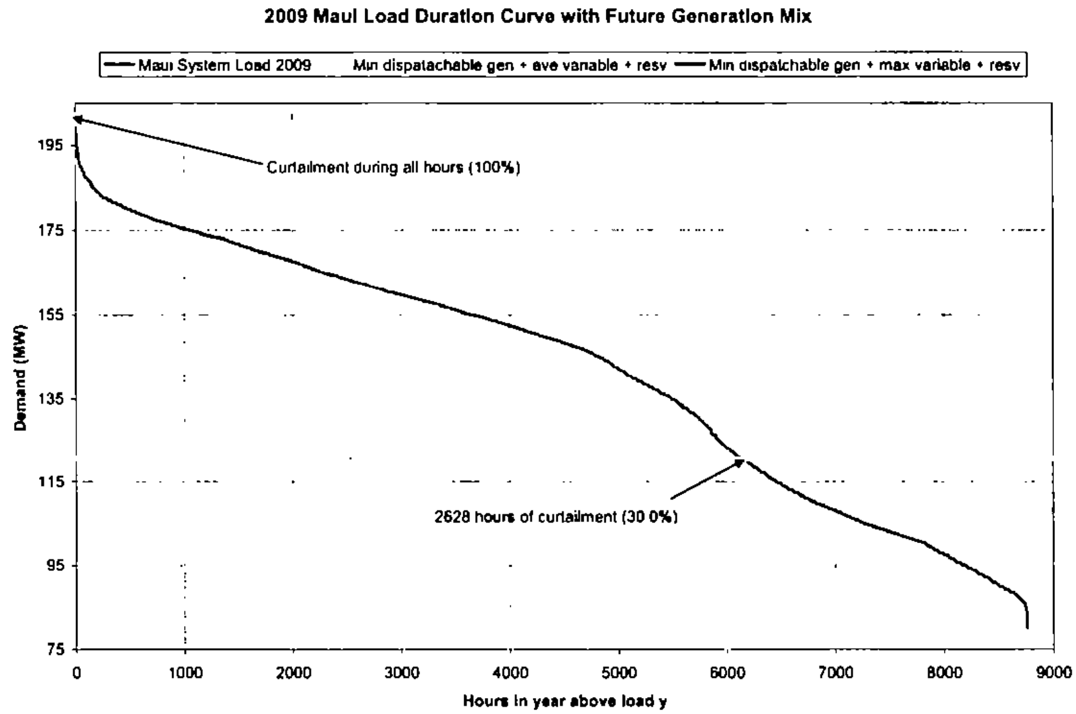


**Figure 6. Load Duration Curve showing potential curtailment hours for average future variable generation, and maximum future variable generation, with minimum dispatchable must-run conventional generation.**

As can be seen in Figure 6, in the absence of load growth, renewable energy curtailments will be much more significant. Depending on the correlation of the variable generation production, the curtailments can range from 30 to 100 percent of the hours in a year. Under maximum variable energy production, there would be very little to no demand to serve. As mentioned above, an assessment should be performed to reevaluate operational requirements for must-run units and reserves considering the future anticipated generation mix.

As indicated in Table 4 below, as of 12/31/09, there are 4.6 MW of variable (mostly PV) distributed resources and 1.2 MW of firm (combined heat and power units) distributed resources interconnected with the Maui System. These consist of NEM and No-sale resources. As these resources are not separately metered, it is uncertain what the actual production from these was in 2008. MECO is presently undertaking projects to help determine the capacity factors and variability of these resources to facilitate improved load forecasting and system planning.

Table 4. Maui DG, Existing and Planned

| **MECO Baseline Summary Breakdown – Maui** As of 12/31/09 | | | | | |
|---|---|---|---|---|---|
| Type of Agreement | Variable PV_Wind_River kW @ 59.3 Hz | Variable PV_Wind_River kW @ 57.5 Hz | Variable PV_Wind_River Total (kW) | Non-Variable Diesel_Propane (kW) | TOTAL |
| NEM Generation | 3,230.8 | 480.7 | 3,711.5 | 0.0 | 3,711.5 |
| No Sale | 401.2 | 0.0 | 401.2 | 1,200.0 | 1,601.2 |
| Schedule Q | 0.0 | 0.0 | 0.00 | 0.0 | 0.0 |
| Existing PPA* | 0.0 | 500.0 | 500.00 | 0.0 | 500.0 |
| TOTAL Existing | 3,632.0 | 980.7 | 4,612.7 | 1,200.0 | 5,812.7 |
| Planned DG | 542.8 | 0.0 | 542.8 | 0.0 | 542.8 |
| Proposed PPA* | 0.0 | 11,060.0 | 11,060.0 | 2,700.0 | 13,760.0 |
| TTL Planned/Proposed | 542.8 | 11,060.0 | 11,602.8 | 2,700.0 | 14,302.8 |
| TTL Exist & Planned | 4,174.8 | 12,040.7 | 16,215.5 | 3,900.0 | 20,115.5 |
| % of 199.9 MW Sys. Peak | % @ 59.3 Hz | % @ 57.5 Hz | % Total Variable | % Non-Variable | % TOTAL |
| TOTAL Existing | 1.8% | 0.5% | 2.3% | 0.6% | 2.9% |
| TTL Existing & Planned | 2.1% | 6.0% | 8.1% | 2.0% | 10.1% |

*Indicates distribution system connected PPAs

Like the HELCO system, the MECO system has a large amount of renewable energy production from existing renewable energy providers. Under present conditions, there are many periods where the renewable energy must be curtailed due to excess energy. MECO is in negotiation to purchase additional variable renewable energy from wind. As this additional energy is variable, the production levels are uncertain; but under various conditions curtailments will occur throughout the entire day.

The addition of distributed energy resources will result in reduced ability to accept renewable energy from the new and anticipated resources. This has an effect on the amount of energy purchased from the new and existing resources, and may also affect the commercial viability of the anticipated resources. As illustrated above, the addition of distributed generation resources has already increased the curtailment of existing renewable energy resources but, as the renewable energy is increased such that curtailment may go into the day time hours, this impact will be magnified with new resources.

In light of the significant excess energy constraints, MECO, like HELCO, proposes to defer additional variable DG interconnection requests on the MECO system, including standard interconnection agreement and NEM requests, until appropriate mitigation measures are identified and employed to appropriately integrate additional variable DG. MECO also plans to defer entering into bi-lateral PPA negotiations with the projects shown as "Proposed PPA"; however, consistent with the Commission's decision and order in the FIT Proceeding, developers may still request, and pay for, additional studies to further assess their project's feasibility. Bi-lateral negotiation cannot be guaranteed, and in fact can only proceed if such additional studies show that projects would not result in significant reliability impacts, significant curtailment of existing or planned renewable generation, or unreasonable costs to ratepayers.

4. Lanai

As discussed in the BEW Report attached hereto as Attachment 5, and as shown in the table below, Lanai has three 12 kV distribution circuits serving the entire island load. One circuit has 1,207 kW of Photovoltaic (PV) and 830 kW of generation (Combined Heat and Power [CHP]). Currently, 1,200 kW of the 1,207 kW of PV installed on Lanai comes from the Lanai Sustainability Research (LSR) facility. The LSR PV system is presently operating at 600 kW until an energy storage device such as a battery system can be installed and fully integrated. Since the full 1,200 kW of the solar facility has not been utilized, there is insufficient history and actual operation to determine how the system will respond to the existing 600 KW and high penetrations of PV. The other two circuits do not presently have any significant renewable resources installed. A detailed IRS was conducted because of the large system and circuit penetration level that was caused by this facility. According to BEW, PV penetration at this level can create reliability and stability issues, if not adequately studied.

Table 5. Lanai DG

| **MECO DG Summary Breakdown – Lanai**<br>As of 12/31/09 | | | | | |
|---|---|---|---|---|---|
| Type of Agreement | Variable PV_Wind_River kW @ 59.3 Hz | Variable PV_Wind_River kW @ 57.5 Hz | Variable PV_Wind_River Total kW | Non-Variable Diesel_Propane kW | TOTAL |
| NEM Generation | 22.7 | 0.0 | 22.7 | 0.0 | 22.7 |
| MECO Owned CHP | 0.0 | 0.0 | 0.0 | 830.0 | 830.0 |
| Schedule Q | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Existing PPA* | 0.0 | 1,200.0 | 1,200.0 | 0.0 | 1,200.0 |
| TOTAL Existing | 22.7 | 1,200.0 | 1,222.7 | 830.0 | 2,052.7 |
| TOTAL Planned | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| % of 4,700 kW System Peak | % @ 59.3 Hz | % @ 57.5 Hz | % Total Variable | % Non-Variable | % TOTAL |
| TOTAL Existing | 0.5% | 25.5% | 26.0% | 17.7% | 43.7% |

*Indicates distribution system connected PPAs

At Miki Basin Generating Station on Lanai, there are two 2,200 kW diesel generators (LL7 and LL8) and six smaller 1,000 kW generators (LL1–6). Historically, LL7 and LL8 were on-line all of the time except for maintenance or forced outage and provided the majority of the base load power and dispatch to serve the variability in the customer load. The 830 kW CHP generator is connected to the distribution system to serve the Manele Bay Hotel. The CHP operates as a base load unit and potentially replaces one of the 2,200 kW Lanai generators (either LL7 or LL8) during minimum load periods. The CHP generator recently became operational so there is insufficient operating history to determine the flexibility and reliability of the generator.

According to BEW, with all of these recent changes to the Lanai distribution system, Lanai needs to evaluate the potential distributed generation that can be incrementally added to the system in order to avoid some of the reliability issues encountered by the other island systems. The preliminary analysis completed as a part of the BEW Report demonstrates the potential for renewable resource curtailments during the on-peak periods. This is especially significant during the light load periods such as April when customer usage is low but solar generation is high.

5. <u>Molokai</u>

As discussed in the BEW Report attached hereto as Attachment 6, the generating resources and distribution system on the island of Molokai are similar in size and function to the island of Lanai. With comparable loads and types of generating resources, the operations and planning requirements are very similar. Molokai has three 2,200 kW Caterpillar generators and other smaller generators that serve a peak load of approximately 5,900 kW. Two or more of these large generators are on-line continuously (with one operating in isochronous mode) to serve load, set frequency, maintain voltage, provide regulation and spinning reserves. At night, one of the generators can be cycled off, depending on system needs. The Molokai electrical delivery system is comprised of five 12 kV distribution circuits serving the island load.

Generators on the HECO and HELCO systems, as well as those on MECO's Maui system, operate under droop control, where the combined inertias of the individual generating units are utilized to resist changes in system frequency during disturbances. Any post-disturbance frequency deviation is then eliminated through Automatic Generation Control (AGC) action on certain generators' turbine governors. The Lanai and Molokai systems, in contrast, do not have a sufficient number of generators nor combined inertia to utilize droop control with AGC, and rely instead on a single generating unit, operating under isochronous control, to regulate system frequency. This type of operation is lacking in inertial response, making it subject to greater swings in frequency (or poorer transient stability) following system disturbances.

As indicated in Table 6 below, today, Molokai has 294 kW of existing DG that creates a DG penetration of 4.9% of the system peak demand. With an additional 139 kW planned DG that the utilities are aware of, this adds 2.3% DG penetration on to the distribution circuits. The projected DG penetration in the near future could rise to 7.3% or higher.

Table 6. Molokai DG

| **MECO DG Summary Breakdown – Molokai** As of 12/31/09 | | | | | |
|---|---|---|---|---|---|
| Type of Agreement | Variable PV_Wind_River kW @ 59.3 Hz | Variable PV_Wind_River kW @ 57.5 Hz | Variable PV_Wind_River Total kW | Non-Variable Diesel_Propane kW | TOTAL |
| NEM | | | | | |
| Generation | 294.4 | 0.0 | 294.4 | 0.0 | 294.4 |
| No Sale | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Schedule Q | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Existing PPA* | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| TOTAL Existing | 294.4 | 0.0 | 294.4 | 0.0 | 294.4 |
| TOTAL Planned | 139.5 | 0.0 | 139.5 | 0.0 | 139.5 |
| TTL Existing & Planned | 433.9 | 0.0 | 433.9 | 0.0 | 433.9 |
| % of 5,950 kW System Peak | % @ 59.3 Hz | % @ 57.5 Hz | % Total Variable | % Non-Variable | % TOTAL |
| TOTAL Existing | 5.0% | 0.0% | 5.0% | 0.0% | 5.0% |
| TTL Existing & Planned | 7.3% | 0.0% | 7.3% | 0.0% | 7.3% |

*Indicates distribution system connected PPAs

Currently, the major difference between Lanai and Molokai is the existing level of DG penetration. However, given the incentives for adding renewable resources and based on projected DG resources planning for the islands, Molokai has the potential for similar excess energy problems during low peak loading conditions and minimum load as the island of Lanai and the other Hawaiian utilities with increasing renewable DG resources such as PV. Given the similarities of the island systems and comparable resources and loads with the island of Lanai, BEW recommends that prudent measures be taken to curb reliability impacts on Molokai by establishing some system limit guidelines and by conducting detailed analyses of existing system data similar to the HELCO and HECO grids to determine the exact system studies that should be completed as DG penetrations continue to increase.

F. <u>Based Upon The Foregoing Determinations And Analyses, Reasonable Limits On Additional Distributed Renewable Generation On Each System Were Developed For This Phase Of FIT Program.</u>

The penetration level of DG on the Hawaiian Electric system is small at this time but significant expansion is anticipated in the next two years. Based on preliminary analysis, it appears that the HECO system can reasonably accommodate new DG from the FIT Program as well as from other interconnection mechanisms including NEM, with more accommodation possible after further evaluations are completed over the course of the year. Additional studies focused on system dynamics and integration of resources will need to be conducted consistent with the systematic and transparent methodology being proposed and discussed in detail below. Until studies are completed, prudent measures to monitor reliability including establishing managed levels of system limits on distributed renewable resources must be exercised.

The HELCO system has a large amount of distributed generation, primarily PV, with significantly more projected in the near term. MECO is also projecting a large amount of PV additions in 2010. In addition, as noted earlier, both HELCO and MECO have preliminary agreements and/or firm agreements in place for transmission-scale and distributed renewable energy additions.

Based on the evaluations contained in Attachments 2, 3, and 4, HELCO and MECO are limited in their ability to take more variable DG due to the significant amounts of existing variable renewable generation already on, or planned for their systems. There would be additional negative consequences to the system, ratepayers, and existing renewable energy providers if additional distributed generation resources continue to be added without mitigating measures (to the extent such can be identified). The HELCO system experiences negative reliability impacts from the presence of large amount of distributed variable generation due to its lack of visibility and due to nuisance trips during underfrequency and undervoltage situations. HELCO and MECO curtail renewable generation today during excess energy conditions, and additional distributed variable resources can significantly impact the level of purchase of renewable energy from existing and new resources planned within the 2010-2012 time frame. On both the MECO and HELCO systems, variable generation contributes to challenges for system balancing, and frequency control has been degraded by certain wind plants despite system modifications made to minimize the adverse effects.

Table 7. Summary of Proposed Reliability Standard Actions

| Island Grid | System Peak Load (MW) | Existing DG (MW) | Existing Distribution Level Penetration | Proposed Action |
|---|---|---|---|---|
| Oahu | 1,200 | 40.1 | 3.3% | Allow DG penetration to 60 MW; conduct further study over course of year to confirm ability to accommodate more. |
| Hawaii | 194.6 | 9.1 | 4.7% | Defer additional variable DG interconnection requests, including standard interconnection agreement and NEM requests, until appropriate mitigation measures are identified and employed. Defer bi-lateral PPA negotiations. |
| Maui | 199.9 | 5.8 | 2.9% | Defer additional variable DG interconnection requests, including standard interconnection agreement and NEM requests, until appropriate mitigation measures are identified and employed. Defer bi-lateral PPA negotiations. |
| Lanai | 4.7 | 2.1 | 43.7% | Defer additional DG interconnection. |
| Molokai | 5.95 | 0.3 | 5.0% | Defer additional DG interconnection. |

The system penetration managed actions shown in Table 7 are proposed to proactively manage the levels of penetration of renewables on each of the island grids and implement operating practices that are aligned with the proposed Reliability Standards/Principles discussed above.

G. Development Of A Transparent Methodology To Evaluate And Be Able To Integrate Higher Levels Of Distributed Renewable Generation On The Island Grids.

As renewable penetration continues to increase with variable renewable generation resources interconnected at both the transmission and distribution levels, a more integrated process of evaluating distribution level impacts on system performance is critical, especially when potential bi-directional flow of electricity may be encountered. The figures below illustrate how distribution and transmission considerations can be integrated into the analysis for interconnecting projects consistent with Reliability Standards and Principles.

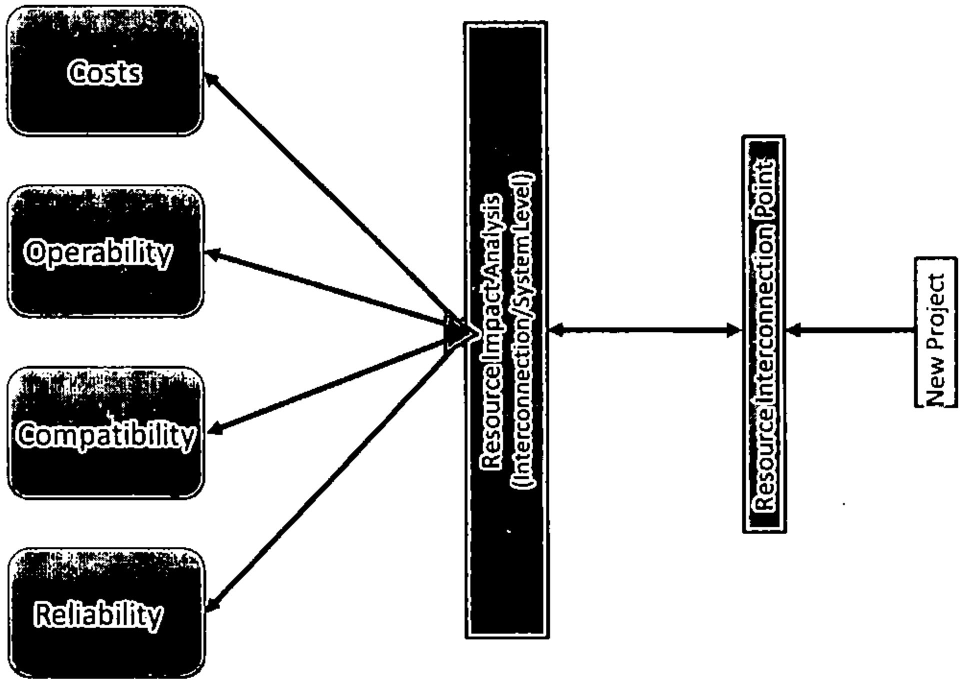


Figure 7. Methodology process flow chart for linking projects impact, utility studies and Reliability Standards.

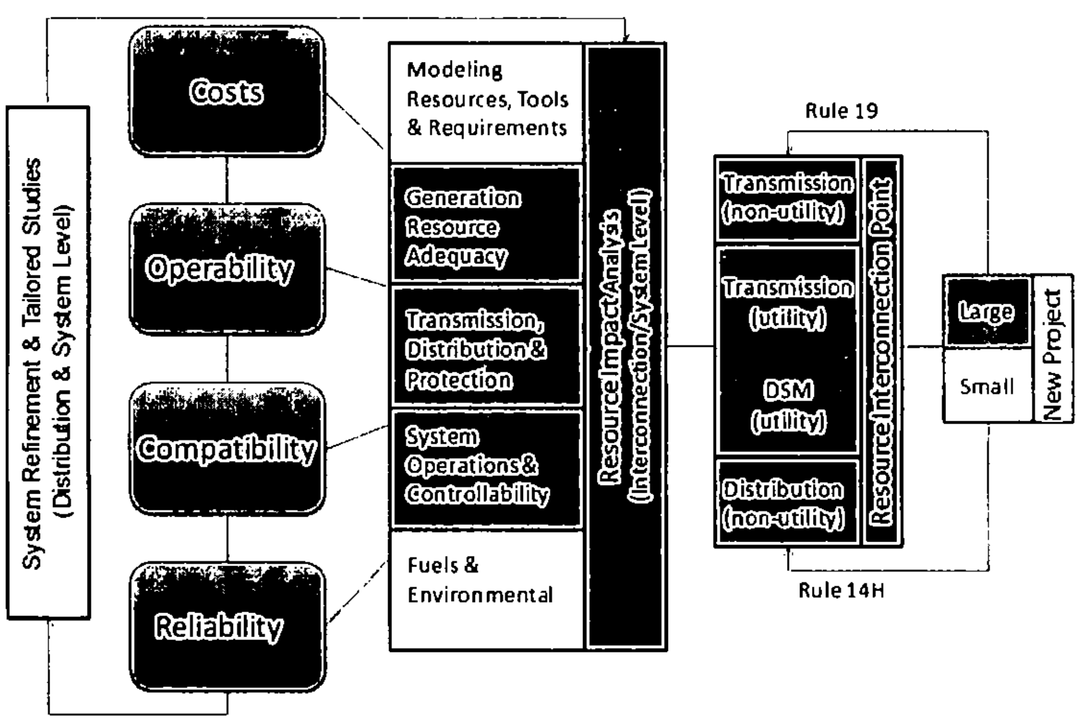

Figure 8. Further details of the Reliability process. Yellow boxes show where stakeholder interaction points and feedback on data, projects will be needed to inform scenario-based modeling and assessments. These are additional considerations to account for the impact of variable resource impacts across the system.

Recognizing that the three utilities are at different stages of renewable and distributed resource penetration on their systems, a consistent methodology for triggering analysis and refinement studies to evaluate penetration levels and assess impacts on reliability has been conceptualized for the FIT proceedings. Studies and the types of studies are categorized by "Level of Criticality" based on impact and degree of penetration. Though consistent in levels, the type and details of the analysis will be inherently different for each of the systems. Figure 9 graphically stacks the Levels for the criticality of studies based on factors including:

1. Associated penetration level,
2. Degree of impact on reliability,
3. Level of difficulty of study and
4. Level of change that may be needed on the system.

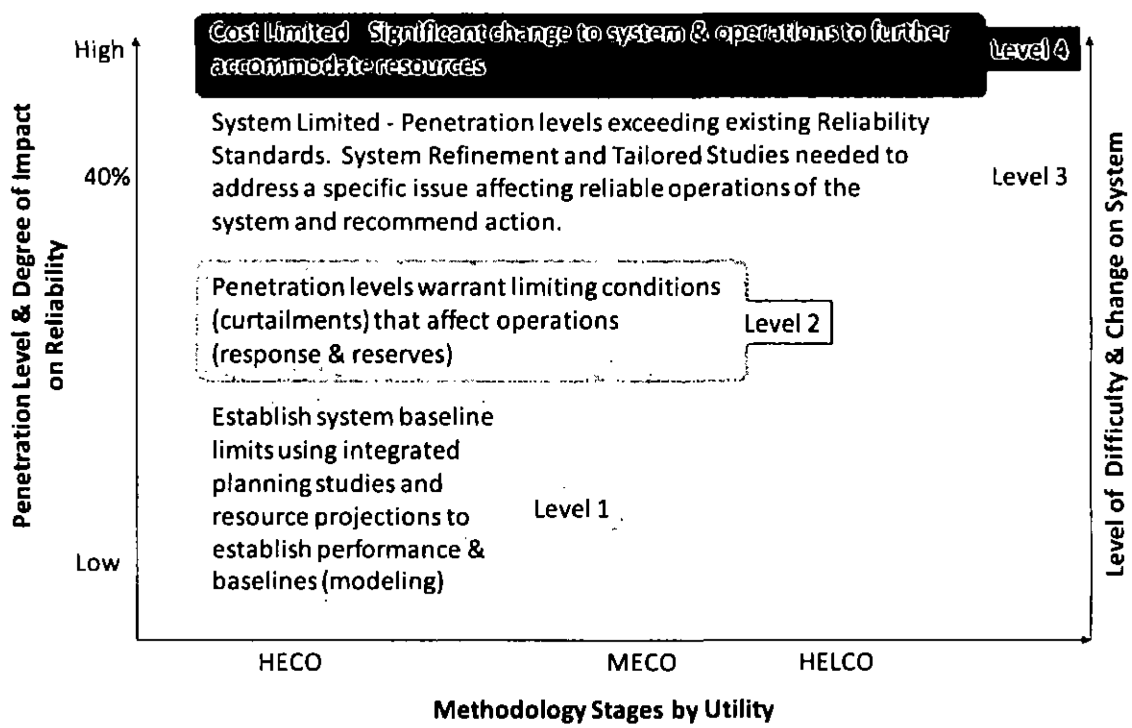


Figure 9. Proposed Level-based analysis and detailed studies that impact reliability assessment Methodology. Results of studies provide recommendations on informing change to system infrastructure and/or standards.

This level based methodology enables the utility to categorize and communicate the potential concerns and impact of specific changes, degree of penetration of resources (either on the transmission or distribution level) and potential changes required to maintain system reliability. From a utility planning perspective, investigative system studies can also be conducted to proactively address and monitor issues based on information being gathered through stakeholder and FIT queuing process. Level 1 through Level 3 studies may be conducted using various levels of penetration and scenario-based analysis to consider options and inform decision makers. Based on the study results, if an action that can be taken today can enable the system to accommodate more renewables, the methodology can be used to stage out the implementation of the changes, seek recovery and proactively prepare the system to accommodate changes.

As discussed above, currently the HELCO system is exhibiting one of the highest levels of renewable penetration from variable and non-variable resources. From a Reliability Standards perspective, penetration levels are causing routine curtailment, reliability impacts and operational challenges which violate three of the four Reliability Standards. HELCO is partially through the Level 3 analysis. System refinement and tailored studies have been conducted and additional studies are immediately necessary to address the reliability issues and recommend action. The reliability and cost impacts of the existing and anticipated levels of distributed and variable generation have not been quantified completely and HELCO may in fact be well underway into Level 4 studies.

The MECO system, with its current penetration levels, is curtailing resources and has already modified its system operation procedures (response and current reserve planning). As additional renewable resources are being planned and proposed to come on line, system reliability and cost impacts are foreseeable. Level 2 studies are necessary to begin proactively managing the integration of additional resources.

A key difference between the HELCO and MECO systems, as compared to the Hawaiian Electric system is that impacts on the power system are evidenced through actual operational data. Many of the challenges on the island systems are dynamic in nature and are difficult to model with conventional utility planning tools. As a result, the actual performance of these power systems is invaluable for understanding the realities of integrating large amounts of variable and distributed generation resources to the larger Hawaiian Electric system as well as to other utilities where such issues remain speculative due to limited penetration. Operational issues have been identified through real time experience on the HELCO and MECO grids. These issues were not anticipated due to lack of visibility of data at distributed generation levels, limited information to understand system wide impacts and limited experience in responding to impacts due to limited penetration on the system either at the transmission or distribution levels.

For Hawaiian Electric, present penetration levels are relatively low and impacts are not yet well understood or seen. But planned distributed resources are quickly rising and impacts on overall system balancing and controls need to be understood with penetration levels on the distributed system projected to be significant. By remaining vigilant and proactive in monitoring, assessing and modeling, the Hawaiian Electric grid can proactively manage increasing levels of renewables on the system using prudent target levels set on the system. Level 1 studies to baseline and proactively plan based on scenario-based analysis is being proposed as the basis for establishing prudent targets. If cost-effective system modifications (based on observed impacts on HELCO and MECO) can be made today to proactively manage for increasing renewables, operational and reliability impacts can be more effectively managed.

H. Facilitating System Change To Better Manage Renewable Resources.

In order to continue to adhere to Reliability Standards/Principles while accommodating the changes in generation mix required to achieve renewable energy goals, evaluations must be conducted to understand the impacts of these resources on the present methods of maintaining system reliability and identify possible mitigation measures. Significant changes to the generation mix, and power system as a whole, can necessitate changes in the operating criteria and action in order to continue operating a reliable power system at reasonable cost. When operational constraints due to variable and distributed generation are identified, solutions can be investigated and evaluated for commercial feasibility and ratepayer impact. In order to accommodate the existing levels of renewable energy (including variable and distributed generation) on the HELCO and MECO systems, and the anticipated levels of variable and distributed generation on the Hawaiian Electric system, a good deal of system evaluation and study has already been completed to identify mitigating measures for existing and future additions. Examples of some of the changes to enhance and facilitate accommodation of renewables include:

1. Changes to Interconnection Standards

As illustrated on the HELCO grid, considerable operational and system control practices have been modified to attain the level of penetration they have today. Even with these changes, system reliability measures, such as frequency control, have degraded from historical performance. In an attempt to mitigate the negative impacts on power system reliability, while accepting the existing high penetration of renewable energy, interconnection requirements have been expanded. The more "grid-compatible" or "grid-friendly" a renewable energy source becomes, the more the system can integrate within acceptable reliability levels. Examples include changing the under-frequency ride through for distribution connected generation to 57 Hz, as currently proposed in the Rule 14H Interconnection Standards. This modification allows for distribution systems to stay interconnected and ride through momentary system interruptions rather than tripping off at the 59.3 Hz level, as loss of the aggregate DG at these low frequencies exacerbated the low-frequency and is presently resulting in either a lower frequency nadir for a loss of generation event and/or additional underfrequency load-shedding. Visibility and control of distribution side DG is necessary for the larger distributed generators, such as for FIT Tier 3 and higher end of Tier 2 systems; and would be necessary for all size of distributed generators as the aggregate output becomes a significant generation source on each island system.

2. <u>Changes to operating actions based on additional studies and observed events</u>

System frequency, voltage and contingencies must conform to system needs and have typically been developed based on experience in operating a portfolio of resources. These operating criteria need to be reassessed as renewable penetration levels increase and as variable resources impact the dynamics of the system. Shown in Table 8 are the Oahu, Maui and Big Island grid's critical frequency, voltage and reserve criteria as they exist today. Changes to these established levels as well as the operational action necessary to accommodate these changes need to be reassessed and defined as penetration levels increase. The highlighted column shows proposed actions that the utilities are proactively conducting or considering maintaining these critical operating criteria for the respective systems.

Table 8. System operating criteria for Oahu, Maui and Hawaii Grids and proposed reassessment needs based on increasing renewable penetration.

| Criteria | Operating Action or Rule | Oahu Grid | Maui Grid | Big Island Grid | Need to Reassess as Renewable Penetration Levels Increase |
|---|---|---|---|---|---|
| *Frequency* | | | | | |
| | - Normal control range | 59 95 and 60 05 Hz supplemental control by EMS | 59 85 and 60 05 Hz, supplemental control by EMS | 59 95 and 60 05 Hz, supplemental control by EMS | *- EMS and generation modifications to improve performance due to high renewable integration. As seen on HELCO and MECO, wind remains driver for system frequency error; the system is unable to keep frequency in normal range during volatile wind periods HELCO has already increased EMS no-control deadband with occasional wind curtailment Higher variable penetrations may require new frequency control scheme<br>- Large amounts of DG requires an enhanced UFLS scheme. UFLS expansion requires additional SCADA (monitoring and control) infrastructure.<br>- HELCO and MECO currently using fast-start units to avoid underfrequency load shed due to wind ramps. Additional variable generation would require additional fast start capacity* |
| | - Emergency control | Emergency condition below 59 5 Hz or above 60.5 Hz Generators switch from EMS to local frequency control (LFC) | Emergency condition below 59 8 Hz or above 60 2 Hz. | Operator action for routine excursions of - 15 Hz Emergency condition below 59 8 Hz or above 60.2 Hz. Manual load shed at 59 5 Hz. | |
| | - Underfrequency Load Shed (UFLS) | First load shed block at 58 0 Hz (instantaneous) | First customer load shed at 58 7 Hz (instantaneous) | First load shed block at 58.8 Hz (instantaneous), time delay block at 59.3 Hz | |
| | - Emergency Reserve Resources | 2 CTs, 50 MW each | Five fast start diesels (2 5 MW each) | Fast-start diesel fleet (28.5 MW, in 2.5 minutes or less) CT1 (less than 10 minutes), CT2 (less than 10 minutes) | |

| Criteria | Operating Action or Rule | Oahu Grid | Maui Grid | Big Island Grid | Need to Reassess as Renewable Penetration Levels Increase |
|---|---|---|---|---|---|
| *Voltages* | | | | | |
| | - Transmission | 138-kV and some 46-kV. Maintained between Low - 0 95 up and High - 1 05 up | 69-kV and 23kV managed to 0 95 to 1 05 up. Studying under voltage load shed incident - may require under voltage relay | 69 kV High limit action levels based on equipment ratings generally 1 05 UP Low limit based primarily upon keeping the distribution level voltages within range . Installed under voltage relays to prevent voltage collapse | *- Need to assess transmission impact of DG including minimum conventional generation for transmission constraints (voltage regulation, line/transformer constraints)<br>- System protection needs to be re-evaluated. DG along radial sub-transmission system requires transfer-trip scheme, may result in underfrequency load shed Analysis of voltage regulations schemes and anti-islanding measures also needed<br>- Voltage regulation requirements from DG requires study. On HELCO and MECO, voltage regulation is required from wind generation resources due to correlation between voltage and power export. To avoid having to operate conventional units for voltage regulation, large variable resources need to provide voltage regulation during zero export On HELCO, geothermal and hydro resources are not presently providing voltage regulation, future agreements will require voltage regulation at the point of interconnection for all transmission-connected resources.* |
| | - Distribution | 46-kV: between 48 and 38 5kV on emergency basis;<br>25 kV and below: shall not exceed 105% of nominal, no less than 90% of nominal on emergency basis | Below 23 KV, managed to 0 95 to 1.05 up | Distribution levels: sub-transmission 34 kV, Pure distribution 12 47 and 13 8 Targets are managed as necessary to provide service within tariff limits | |
| | - VAR/voltage regulation | System voltage/VAR regulation determined by System Operation and normally controlled via each generator's Automatic Voltage Regulator (AVR) control system and/or system capacitor banks. | All conventional units operate in voltage regulation mode to hold voltage to the target specified by the system operator. | All conventional units operate in voltage regulation mode to hold voltage to the target specified by the system operator<br>- Diesel generators provide bank regulation<br>- Voltage regulation at the point of interconnection required from transmission side wind energy suppliers.<br>- Larger provider on the distribution system has been required to provide power factor control<br>- Regulation to the point of interconnection by IPP is to a target specified by the system operator. | |

| Criteria | Operating Action or Rule | Oahu Grid | Maui Grid | Big Island Grid | Need to Reassess as Renewable Penetration Levels Increase |
|---|---|---|---|---|---|
| *Reserves* | | | | | |
| | - Must-run units | Dictated by weekly schedule from System Operations Engineers | K3, K4, M14, M15, M16, M17 or M19, M18, and HC&S at minimum load | Includes three steam units, two combined cycle facilities (in single train, one train may cycle), and a geothermal facility | *• On HELCO and MECO, a re-evaluation of baseline must-run units is needed to assess system stability, provide for inertia and ramp rates to meet peak loads<br>• As seen on HELCO and MECO, the regulating requirement has increased substantially in number and magnitude. Research needed in forecasting to provide operators indication of high-probability periods for wind ramps and/or variability allowing prudent operator action Such forecasting not presently available through commercial forecast services<br>• The present downward reserve requirement for HELCO and MECO is insufficient for large loss of load events and designed for minimum load periods Need to reassess size of downward reserve for future operating scenarios where excess energy conditions will occur throughout daytime loads New and existing non-dispatchable resources need to provide high-frequency ramp-down to avoid over-frequency conditions<br>• Upward regulation has increased significantly for HELCO and MECO with the addition of variable, must-take resources which force generation to operate at part-load Analysis needed to* |
| | - Generation Reserve | Enough spinning reserve to meet loss of largest operating unit, will not be reduced by amount of interruptible loads available, on-line spinning resources | Covered by regulating reserves | Enough reserve capacity is available, considering anticipated demand and maintenance outages, to cover for the loss of the largest operating unit. The total reserve capacity includes offline resources available within four hours. | |
| | - Downward Regulation | Enough for loss of largest feeder on HECO, 35 MW | 2MW per CT online (6 to 8 MW) | Sufficient generation online and immediately responsive to AGC to largest off-peak demand loss due to a single contingency (transmission line loss with distribution tap load) | |
| | - Upward Regulation | covered by spinning reserve | 6MW or 50% of wind power output | Sufficient generation online and immediately responsive to AGC as necessary to manage anticipated changes in increases in apparent demand (customer demand plus decrease in variable generation production) within the next hour | |

3. <u>Improving generator dispatch and flexibility and response</u>

As part of the Inter-Island Wind studies currently being conducted at HECO, unit tuning studies are being conducted to improve the operational response of conventional units and assess the cost impacts s of making modifications. On the HELCO and MECO systems modifications have been completed to expand the operating range and response capabilities of various units and change the reserve policy to mitigate frequency control issues created by the existing levels of variable wind generation. (See, Attachment 3, Evaluation of System Balancing and Frequency Control). However, even with these modifications, the variable wind production currently installed on both systems is the primary driver for frequency error on those systems. With increasing variable renewable energy, it is evident that additional studies are necessary in order to and assess the impact of variability on the operating criteria and reliability across the systems, identify mitigation measures, and evaluate costs.

I. <u>Routine Monitoring And Assessment Of Resource Modifications</u>

As part of the methodology to obtain timely input for resource assessments the following timelines for conducting baseline inventories are proposed along with utilizing tools that are being developed as part of the CESP and FIT queuing processes to periodically disseminate information to industry. This complies with the routine periodic review and 2 year evaluation period established in the Commission's Decision and Order.

Based upon the assessments contained in the Attachments hereto, specific issues and follow up recommendations are highlighted below. Specific studies and levels of study (Level 1-4) may need to be pursued per the recommendation of each utility based on observed and planned penetration levels.

**Issue: Excess Energy Curtailment**

Increasing the renewable energy percentage above that already in place for the HELCO and MECO systems, which are anticipated to be very high, can occur only if demand is increased or if "renewable energy is added to the system which can provide the same grid benefits (i.e.; frequency response, inertial response, dispatch capabilities), and therefore displace, must-run conventional units. The addition of dispatchable, firm capacity biomass and geothermal is expected to provide such benefits. An additional benefit of such renewable energy providers is the superior capacity factor. The combined effect is achieving a much higher renewable energy percentage than could be achieved through additional variable resources. Any further changes in generation mix for the HELCO and MECO systems will require an evaluation of costs and necessary unit characteristics.

**Recommendations**

- Additional mechanisms to promote DG in order to increase renewable energy (RE) are not recommended for HELCO and MECO as these resources will result in a significant decrease in the ability to purchase RE from existing and anticipated RE resources. The existing and near-term DG may affect the commercial viability of anticipated RE additions as purchases may be less than prior studies indicated for the anticipated additions.
- The capacity factor and variability of the existing and planned variable DG should be determined and incorporated into planning and operational time frames. Of particular importance are the impact upon the load forecast and load duration curve, and the impact upon frequency control and regulation.
- The operating criteria for frequency control and load following (reserves, ramping capability, etc) needs to be evaluated for the future operating conditions, to consider extended hours of curtailment periods (units operating at near minimum loads) and impact of the distributed variable generation.
- Analysis should be performed to understand the cost impacts of operating at very low efficiencies, to accept existing and anticipated RE resources, with consideration of the reduction in load from existing and planned DG. This cost consideration should consider the sensitivity to changes in fossil fuel prices.

**Issue: Reliability Impacts at the System and Circuit Level due to large amounts of Variable Distributed Generation**

**Recommendations**

- Additional studies are required as soon as possible to evaluate the impact of the existing and projected levels in the following areas:

- System stability through faults and contingencies
- Modifications to system protection including underfrequency and under voltage schemes
- Interconnection requirements for DG including underfrequency and under voltage ride through to ensure system remains operable through faults and contingencies. These would be included into interconnection requirements for DG (Rule 14H).
- Changes to operations necessary to ensure the system remains stable through faults and contingencies (such as modification of reserves)

- Field verification is required to ensure that changing undervoltage and underfrequency trip settings results in the desired ride-through during disturbances. Additional discussions with manufacturers and installers should take place to ensure the requirement is interpreted as a ride-through rather than a maximum clearing time (which could mean the inverters may trip sooner). Expanded off-normal frequency and voltage ride-through is a requirement that is not implemented at other utilities and therefore the inverter performance during off-normal frequency and voltage conditions is not proven in actual utility-connected operation.

- The cost impacts of the DG need to be better understood, including the contribution to system balancing and frequency control issues, displacement of other renewable energy resources, and contribution to excess energy conditions.

- Research a means for monitoring and control of the existing DG is required as the penetration level is equivalent to one of the larger HELCO units and therefore significantly affects real-time operational decisions. A forecast of the variable PV is necessary for unit commitment and may require changes to reserve policies for effective frequency control. The impact of DG during system restoration could be significant as the DG will automatically reconnect in reenergized portions of the grid.

- Additional DG connections should be delayed until the analysis above has been completed, and mitigation measures in place to ensure there are not excessive negative impacts on ratepayers or reliability. To facilitate study, more data is required. HELCO has undertaken a project to collect PV data to gain better understanding of capacity factors, variability, and correlation between sites, generation profile, and resource availability in various regions.

**Issue: Impact of variable distributed generation, on system balancing and frequency control.**

**Recommendations**

- The HELCO system has maximized variable generation. Additional variable generation will add to excess energy and frequency control and balancing problems and such additions therefore should be minimized. Of particular concern is variable generation that will increase the second to second frequency error beyond that already caused by variable wind generation, which would require increasing the "no control" deadband for secondary frequency control by AGC.

- The existing units providing primary and secondary frequency control and regulation cannot be displaced except by units providing the same or better frequency control and regulation characteristics. Generation additions of any significant amount (in aggregate or individually) need to participate in primary frequency control.
- Changes in generation dispatch mix need to be analyzed to ensure that the system remains stable through faults and contingencies in the primary control time frame and to define operational reserve policies to ensure sufficient response capabilities in the secondary and tertiary control periods.
- Data regarding the existing and anticipated PV characteristics is required in order to study the operational impacts on frequency control and balancing. A pilot project based on collecting data and numerous substation locations is in progress. This data can be used to modify load forecast and develop an understanding of impacts on reserve requirements.
- The droop response for all conventional units should be improved if not presently able to achieve 4%. Work has been completed for one governor replacement and projects are underway for two more steam units.
- Continue research into possible ramp forecasting techniques.

These proactive measures are being proposed as a means by which the utilities can continue to reliably and cost-effectively manage the changes anticipated on the systems.

At this time, evaluation of the variable DG impacts is difficult due to the absence of data because the majority of the existing variable DG is not visible to the system operator. The typical capacity factors for PV resources of various sizes, variability due to environmental and weather patterns, and correlation between sites are not known. Larger DG sites (FIT Tier 3) will be required to have SCADA/EMS interface, but at present, cost-effective means through which to communicate and control the numerous smaller DG resources throughout the system and bring the data to the System Operator through the SCADA/EMS system are not commercially available. Through recently awarded American Recovery and Reinvestment Act (ARRA) funding and national laboratory collaborations, the utilities are in the process of deploying monitoring devices to begin pilots for collecting, assessing and visualizing real-time distribution level data throughout the islands. Through new technology initiatives, such as smart grids, and collaborations with mainland utilities, the Hawaiian Electric Companies are seeking proactive means to investigate, demonstrate and deploy possible technologies for evaluating impacts and operational strategies to continue managing new resource additions.

Examples of tools and proactive measures include the following examples:

1. <u>Real-time Solar Monitor for Operations</u>

HELCO has implemented a project to collect information on solar PV production and begin assessing potential capacity factors, variability, and correlation between sites. Information collected on availability of solar energy from sites across the Big Island is telemetered in real-time back into the Operations center. Shown in Figure 10 color-coded circles provide an indication of the level of available solar energy around the island collected from field devices.

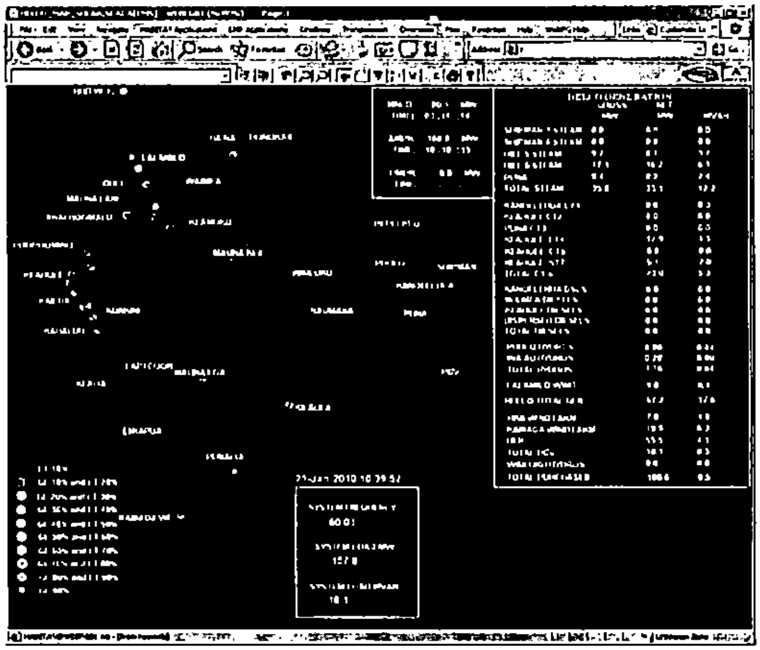

Figure 10. Real-time display on the HELCO EMS being piloted to monitor available solar energy around the island.

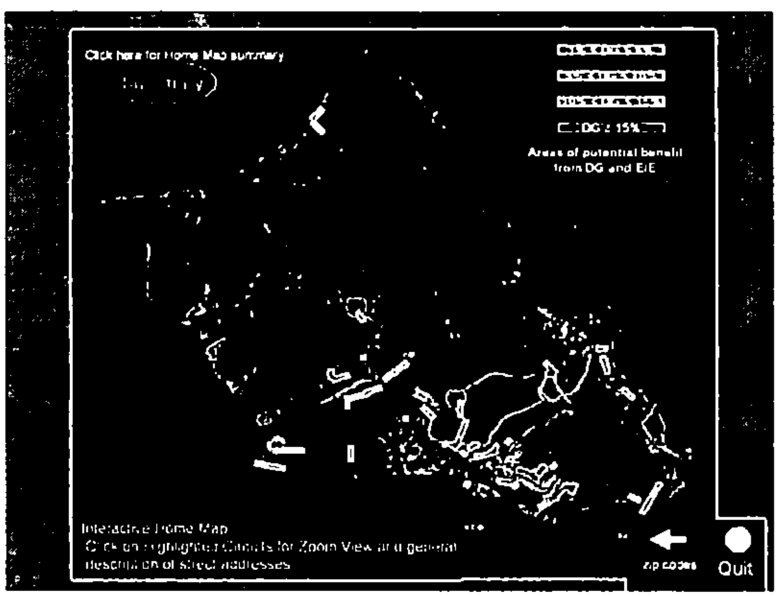


Figure 11. Location value map of Oahu showing various distribution circuit penetration levels.

The Hawaiian Electric Utilities have developed location value maps (LVM) for all five islands (Hawaii, Oahu, Maui, Molokai and Lanai) to provide the public access to information on the value of various distributed resources on the island grids (An example of an LVM map is shown above in Figure 11). Developed with open dialog with the industry, levels of detail on penetration impacts on the distribution grid are now available for the first time via an interactive visualization tool to help industry identify opportunity areas and minimize project delays by avoiding highly loaded distribution circuits.

These types of transparent processes are measures and are being proposed as part of a transparent methodology.

HECO will be developing a more centralized process to monitor the interconnection applications from the various resource contracting mechanisms. This information will serve to continually monitor the status of the interconnection work in process and identify areas for potential efficiency consolidations. In addition, the status of projects either in process or completed can provide regular feed back for conducting short range and long range system planning and operating studies.

**Attachments**

1. BEW's HECO DG Analysis Methodology and Recommendations
2. Evaluation of Distributed Generation Resources
3. Evaluation of System Balancing and Frequency Control
4. Evaluation of HELCO and MECO Excess Energy and Cu
5. BEW's MECO-Lanai Analysis Methodology and Recommendations
6. BEW's MECO-Molokai Analysis Methodology and Recommendations

**References**

1. S. Fink, C. Mudd, K. Porter and B. Morgenstem, *Wind Energy Curtailment Case Studies*, NREL/SR-550-46716, October 2009
2. C. Hubert, *Electric Machines: Theory, Operation, Application, Adjustment and Control*, Prentice Hall, October 2001

**Definition**

| | |
|---|---|
| Reliability Standards | as defined by the Hawaiian Electric Utilities, are established principles that govern the planning and operations of the electrical system to maintain the delivery of reliable power from generator to load. Sound electrical planning, operating practices, engineering guidelines derived from operating experience and engineering studies are the basis for |

| | |
|---|---|
| | the development and application of such standards. |
| Net System Load | System maximum load minus losses |
| Must –run units | Generation units that must remain online (cannot be cycled offline and online) to maintain system reliability and the ability serve load. They provide dispatchable critical grid services to stabilize system through faults and contingencies, voltage and frequency regulation and load following. |
| Must-take units | Generation units whose output is accepted onto the system regardless of cost, as long as the system can accommodate the generation from those units. These systems may include run-of-river hydro, waste to energy, distributed generation (load-offsetting and export) which are not monitored or controlled by system operators (i.e. does not have SCADA interface). |
| Load offsetting distributed generation | Distributed generation which is generated and consumed by the local load. It is a no-sale such as NEM. |
| Exporting distributed generation | Distributed generation which is generated for purposes of exporting onto the grid for sales such as FIT. |

Attachment 1

# DISTRIBUTION GENERATION (DG) RELIABILITY STANDARDS DEVELOPMENT PROCESS

# FEED IN TARIFF DOCKET NO. 2008-0273

## HECO DISTRIBUTION SYSTEM ANALYSIS

February 8, 2010

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Attachment 1

# Methodology for Modeling of Distribution Generation (DG) Resources on the HECO Grid

## Table of Contents

# 1. INTRODUCTION

HECO has designed its generating power plants to serve the base load requirements and economically dispatch to serve customer load. The units were not designed to dispatch and cycle due to high penetrations of variable generating renewable resources. HECO is required to provide spinning reserves for the largest unit generating which is 180 MW. If HECO is also required to provide spinning reserves for a percentage of the variable generating renewable resources, such as wind and solar, the existing units may not have high ramping capability or fast start up times to support the required spinning reserve requirements. HECO is concerned about under frequency, voltage, and other system reliability issues due to the delay in ramping of units to serve load. There may be conditions where HECO must curtail load during these ramping times.

Currently, HECO does not have a high penetration of DG PV renewable on its system. HECO does have several distribution feeders with penetrations approaching 15% penetration but has not completed a detailed analysis on the potential impacts to system reliability due to these high penetrations. HELCO and MECO are already experiencing system balancing and frequency control problems, the need to curtail renewable resources due to excess energy, as well as stability and reliability issues due to the high penetrations of variable generation. These issues have already been identified by HELCO for high aggregate amounts of distributed variable generation. Therefore HECO wants to study its system operations and possible dynamic stability and reliability impacts prior to increasing DG penetrations.

This report highlights some of the potential issues on the existing generating system that must be studied to determine the flexibility of the generating system, facilitating higher penetrations of renewable resources. As will be discussed in this report, the major problem is designing or modifying the existing generating resources to support load and variable generating renewable resources. HECO also needs to study the distribution system operations and switching routines, as well as the dynamic response of the system through faults and contingencies under future operating scenarios, to ensure that the system remains stable under various operating conditions.

# 2. CONCLUSIONS

An initial DG penetration level of 60 MW is deemed feasible, based on high level steady state scenario analysis. Several tens of megawatts more of DG could possibly be accommodated, however additional more refined studies are needed to confirm this. HECO will conduct these studies over the course of the next year, in time to support the next FIT Reliability Standards update.

HECO needs to complete planning and operating studies on its entire transmission, distribution and generating system to determine infrastructure upgrades and changes needed to support higher penetrations of variable generating resources.

Over the next several years, HECO will solicit and negotiate renewable resource contracts to meet its Renewable Portfolio Standard (RPS) requirements with DG resources as part of the RPS resource mix. Before these resources are contracted, HECO needs to develop a methodology to plan and analyze resources. The basic methodology is explained later in this report.

## 3. DISCUSSION

resources are designed

HECO planned its generation resource mix to provide firm base-load and peaking generating resources to serve HECO electric customers. Installed base load to be generating twenty-four hours a day at maximum capacity, unless forced out of service due to an outage or scheduled off-line maintenance. The base-loaded units are the most efficient steam units and are not designed to be cycled; they have the capability to ramp up and down from minimum to maximum rating to follow customer load. The ramping capability is intended to help restore the system frequency to 60Hz whether the deviation is due to a change in load demand, an upset condition among the interconnected generating units, and/or an upset condition on the transmission and distribution system. The ramping rates needed for the two latter conditions is typically much greater than that for customer load following. The cycling units are smaller and less efficient steam units that start up and shut down on a daily basis to follow changes in customer load. If the base load and cycling steam units are shut down, the start-up time from cold or warm boiler temperatures to minimum load can take hours. The third type of generating resources is peaking units, which are designed to quickly start up to meet peak demand for relatively short periods. These units can be started in 10 to 30 minutes, are expensive to operate and have limited operating hours annually.

HECO normally adds 5 MW to the minimum load value for downward regulation. HECO is required to have spinning reserve capacity for the loss of its largest generating power plant. The largest generating plant on the HECO system is AES, currently rated at 180 MW. The generating plants on line must share the 180 MW spinning reserve (up) requirement by reserving an increment of generating capacity in case there is a loss of the largest generating plant.

At the time that these generating units were planned and constructed, the new variable generating renewable resources such as wind and solar and customer-owned generating such as residential and commercial solar facilities were not anticipated to be at such penetrations. The impact of these new renewable resource on the existing generation facility needs to be further assessed.

The HECO transmission system consists of the entire 138 kV system and portions of the 46 kV system. The high voltage 138 kV transmission system is designed to move large quantities of power around the island to lower voltage distribution substations. The 46 kV transmission system is located in the downtown Honolulu area and primarily serves downtown Honolulu loads. The rest of the 46 kV system serves distribution substations and converts power from 46 kV to 12 kV to serve customers. The distribution substations are designed to move power in one direction (from the high voltage to the low voltage). The relay protection devices are not designed to move power in the bi-directional mode. Here again, the new renewable generating resources connecting to distribution have created unique new challenges for HECO system planning.

From the transmission and generating perspective, customer owned facilities, installed under NEM and small distributed generating plants (DG resources) on the distribution system, planned to be installed under the Feed-in-Tariff (FIT) are viewed by the transmission system as load reducing facilities. The transmission system and HECO power plants only see lower loads to be served. However, if the DG and/or Net Energy Metering (NEM) facilities are out of service, or there is a sudden loss of generation due to environmental conditions, the power plants must respond to the sudden increase in load.

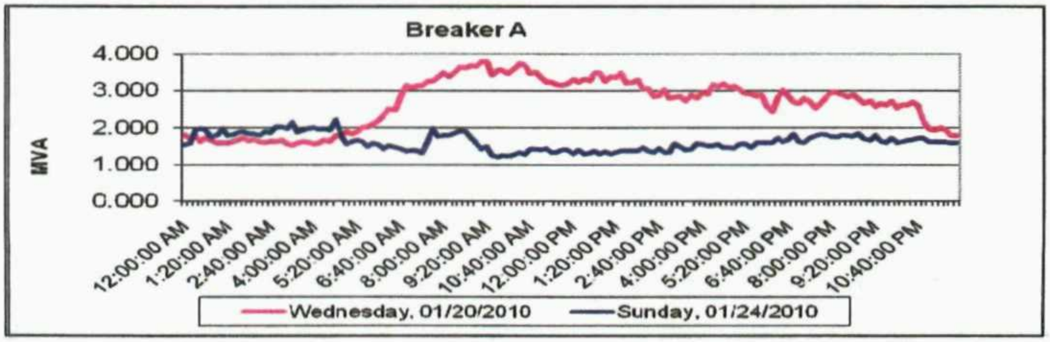
The Hawaii utilities are meeting a 2010 RPS target of 10% and an ultimate renewable energy target of 40% by 2030. This requirement is referred to as the Renewable Portfolio Standards (RPS). These renewable resources are a combination of solar, wind, geothermal, hydro and bio fuels. The 2010 renewable energy target is 10 % of the total customer energy consumption. These resources can be connected to the transmission grid or the distribution circuits. Under FIT, distributed renewable facilities are included in the RPS portfolio.

Since wind and solar resources are variable generating resources with generation controlled strictly by wind and sunlight conditions (environmental conditions), the utility lacks control as to when and at what level the renewable resources generate. The utilities must change their planning and operations to accommodate these new resources. This is particularly challenging for those units that provide system balancing; in the absence of proper advance planning, the operations of many of the existing base load and cycling units may need to be further reevaluated.

The utilities facilitate the installation of DG resources into the system grid where possible. HECO's current DG interconnection tariff Rule 14.H states that when the aggregated total of DG resources exceeds 10% of the distribution feeder peak for the year, the utility may require a detailed distribution feeder study to determine if it is feasible to connect the resource, and if so, to identify any interconnection requirements over and above the standard interconnection which are required to safely and reliably interconnect. Under the Hawaii Clean Energy Initiative (HCEI) Agreement, HECO is planning to modify the study trigger level from 10% to 15%, and filed a proposal to the PUC to this effect in January 2010. In the same filing, HECO also proposed another criterion which may trigger a detailed distribution feeder study, namely that the total capacity of all DG resources cannot exceed 33% of the minimum feeder load at the time when the DG resources are available. The purpose of these criteria are to identify when the DG resources become large enough, relative to the demand on the system, to require additional resources become large enough, relative to the demand on the system, to require additional technical solutions to avoid negatively affecting reliability and power quality for all connected to the distribution circuit.

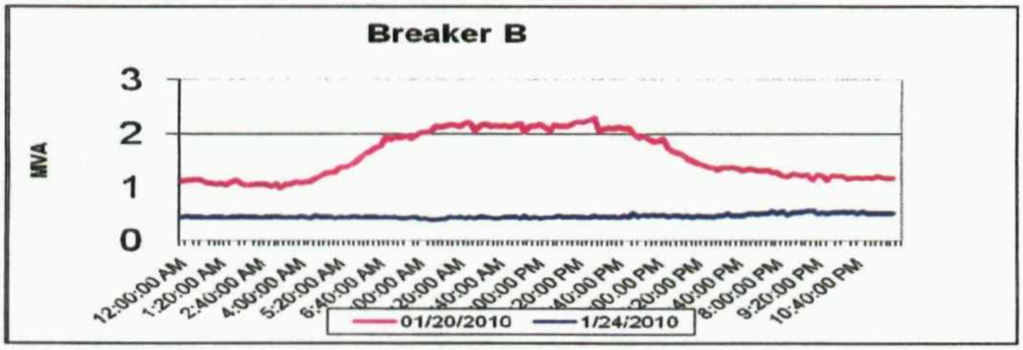
Two examples are shown below (Figures 1 and 2). Neither of these examples represent the actual feeder peak day or the minimum on-peak load. The two days are for Wednesday, January 20, 2010 and Sunday, January 24, 2010. For Figure 1, Breaker A has an on-peak maximum load of 3.479 MW. The maximum on-peak load during the minimum peak day occurs on Sunday, January 24, 2010 is 1.438 MW. The peak occurs during the maximum PV generating period between 11 am and 2 pm.

**Figure 1 Breaker A Comparison of a Sunday and Weekday Profile**




In Figure 2, the maximum peak load for Breaker B is 2.29 MW, however, the maximum load during the low load period on Sunday is 470 kW.

**Figure 2 Breaker B Comparison of Sunday and Weekday Profile**




The above graphs illustrate the need to assess the feeder loading not only at peak period but also on the days where the loads are not as high. The weekend loading of the circuits represent a challenge to the utility due to the fact that the loads are lighter but the DG resources will still be able to output the same level as weekdays output. The feeder study must assess the condition of highest DG/demand ratio, in order to avoid potential adverse affects to all connected to the distribution circuit.

The feeder study determines if there is the potential for reliability and operating problems with higher penetrations. If the distribution feeder can support additional DG resources, then the utility can continue to add new resources. If one of the two criteria creates reliability problems, then the utility can stop accepting new DG resources on the feeder. The issues that are assessed in relation to the feeder penetrations are those issues that generation can cause at the circuit level which include but not limited to voltage regulation, transient voltage, reactance energy, flow back power, relay and protection coordination, switching under contingency analysis and islanding risks.

In addition to having penetration limits on the distribution feeders, there is also a practical limit on installed DG across the total island power system, beyond which the total power system may experience noticeable operational and reliability impacts. It is important to understand the difference between the circuit penetration limits which trigger study under Rule 14.H, and the system-wide penetration limits at which the total power system begins to experience negative system impacts. The distribution feeder limit is based on each feeder's non-coincident peak load that could occur at different times for each feeder (non-coincident peak). For a total system DG penetration limit, the percentage is based on the maximum peak for the entire system that occurs at the same hour (coincident peak). Due to the confusion created when speaking of system penetration in terms of percentages of system peak loads, it is preferable to express a system-wide limit in terms of installed megawatts of DG capacity.

Generating facilities under the FIT program are either demand reducing if connected to the distribution system or new generation if connected to the transmission or sub-transmission system. FIT Tiers 1 and 2 resources will be connected to the HECO distribution system. FIT Tier 3 can be connected to either the distribution or transmission/sub-transmission systems. DG resources can also be variable – such as PV – or firm, such as biofueled generation. HECO has not forecasted the potential proportions of variable and firm DG, but based on the types of technologies eligible for the FIT and experiences at HELCO, it seems likely the majority would be variable PV. For this report, the DG resources are anticipated to be PV.

In order to reasonably frame the system-wide impact of different levels of PV on the HECO system, BEW conducted steady-state modeling of the HECO system with various levels of DG PV penetration – 5%, 10%, and 15% – in combination with two different scenarios of sudden loss of aggregate PV generation, one in which 25% of the island-wide installed PV output is lost and another in which 50% is lost.

PV facilities generate during the day time hours and are seen by the System Operator as demand reduction when connected to the distribution system. In Figure 3 below, the April 2010 forecasted light load daily profile is adjusted by DG penetrations of 5%, 10% and 15%. The light red shaded area is the first 5% DG penetration. The summation of the first and second DG areas represents 10% DG penetration. All three red shaded areas represent the full 15% DG penetration. As shown in Figure 3, the DG PV has a significant impact on the mid day load profile but has no effect on the remaining hours.

**Figure 3 Impact of DG PV on HECO April 2010 Minimum Load**

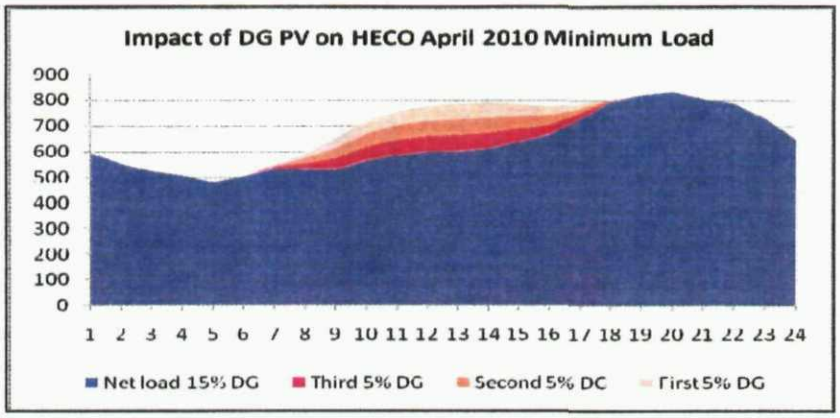
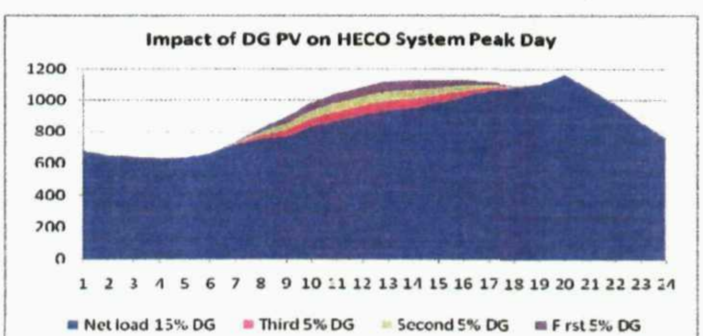



Figure 4 below shows the DG PV impacts for the system peak day. Given that the peak value is higher, the impact of DG PV on the system peak day load profile is not as dramatic. These two figures support the concept that DG PV facilities will have a more significant impact on the light load period. HECO may have fewer generating plants on line and more plants on minimum load during periods of high PV generation. The variability of the PV energy and the limitations on generating unit ramping could create the potential for under frequency and system stability problems. This anticipated displacement of demand during daytime peak hours is confirmed by the experience at HELCO. A comparison of the 2008 and 2009 load demand curves shows a decline in the mid-day load, while minimum and peak demand remained relatively unchanged. This is believed to be the effect of daytime production from the distributed PV on the HELCO system added in that time period.

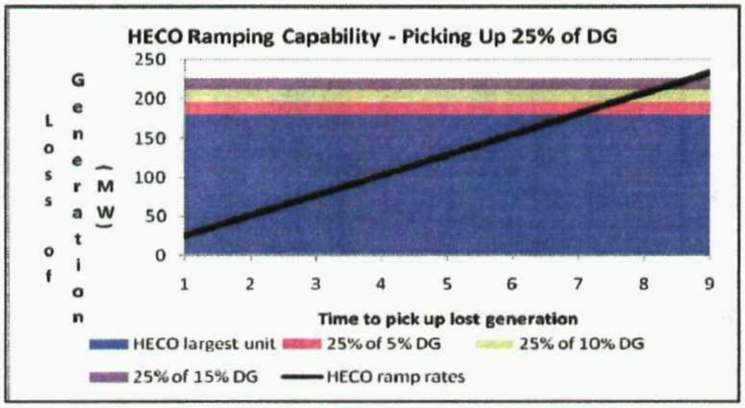
**Figure 4 Impact of DG PV on HECO System Peak Day**



If the system peak is 1,200 MW, then the maximum DG penetration is 180 MW for a 15% penetration. If HECO must include this total variable capacity in its spinning reserve requirements, then the total spinning reserves could be as high as 360 MW at any single point in time. Although it is reasonable to assume that not all of the installed PV capacity on the island will be lost simultaneously as a result of cloud cover due to geographic diversity of the PV installations, this may not be a reasonable assumption during abnormal grid operating conditions such as during under frequency events. In Figure 5, if both the AES 180 MW generating unit and only 25% of the 180 MW DG PV (45 MW) go off line at approximately the same time, the remaining conventional resources must pick up the full 225 MW. The ability of the remaining systems to ramp up to serve the displaced load needs to be evaluated. Issues include under frequency issues, stability and dispatchability. Depending on the load at the time of the outage, the response of the other generating resources on the system due to under frequency issues may also have to be addressed. Load shedding may be a consequence if the system is unable to meet the load.

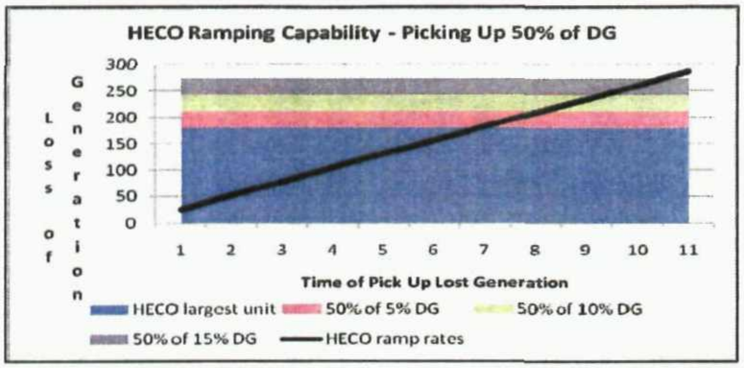
If the total amount of installed DG is at 5% of the HECO system peak (60 MW), the corresponding 25% DG loss scenario equates to significantly less (15 MW) additional load to be picked up by HECO's system, along with the 180 MW attributed to AES. It would take roughly 7 minutes to ramp up generating capacity to serve the displaced load.

**Figure 5 HECO Ramping Issues with 25% DG Outage**




In the scenario shown in Figure 6 below, if 50% of the DG PV (at a 15% penetration level) goes off line during the first seven minutes while the generating units are ramping up to serve the 180 MW of AES due to under frequency, it could take up to 11 minutes to serve the 270 MW of unserved load. Figure 6 below shows the time to pick up the unserved load. This situation could cause more PV to go off line and would increase the load shedding requirements.

**Figure 6 HECO Ramping Issues with 50% DG Outage**




Although further studies are needed including collection and analysis of coincident island-wide PV operating data and dynamic system modeling, based on BEW's scenario modeling, it appears reasonable to conclude that no significant system operational or reliability impacts are likely if the total installed DG capacity on the HECO system is at 5% (60 MW) of the total system coincident peak demand. The actual acceptable installed DG capacity may be higher than this amount by several percentage points; further studies will better determine this.

In addition to managing the overall installed capacity of DG based on the scenario modeling, the following reliability requirements for DG are recommended in order to avoid the difficulties that HELCO and MECO are currently experiencing with load balancing and frequency control, and curtailment of renewable generation due to excess energy conditions during lower demand periods:

- Lower the frequency trip of PV resources to 57.0 Hz. This enables the PV to stay on line longer and not trip too quickly due to under frequency. It is critical to the system stability to have as much as generating resources on line as possible during low frequency excursions in order to prevent the system frequency from a potential collapse which may lead to an island wide blackout. In addition, HECO should evaluate under voltage ride-through requirements.
- Require all DG facilities greater than 500 kW to install a SCADA system in order to provide visibility of the Tier 3 resources to the HECO system. In addition, the ability to monitor and control the DG facilities will enable HECO to manage and respond to system events associated with the variability of the renewable resources.
- Determine the total system penetration of non-dispatchable renewable resources to a system level that avoids excess energy conditions. As individual feeder penetrations are studied, excess energy may create flow-back conditions.

# 4. METHODOLOGY FOR STUDYING AND EVALUATING RENEWABLE RESOURCE IMPACTS ON THE HECO DISTRIBUTION AND TRANSMISSION GRIDS

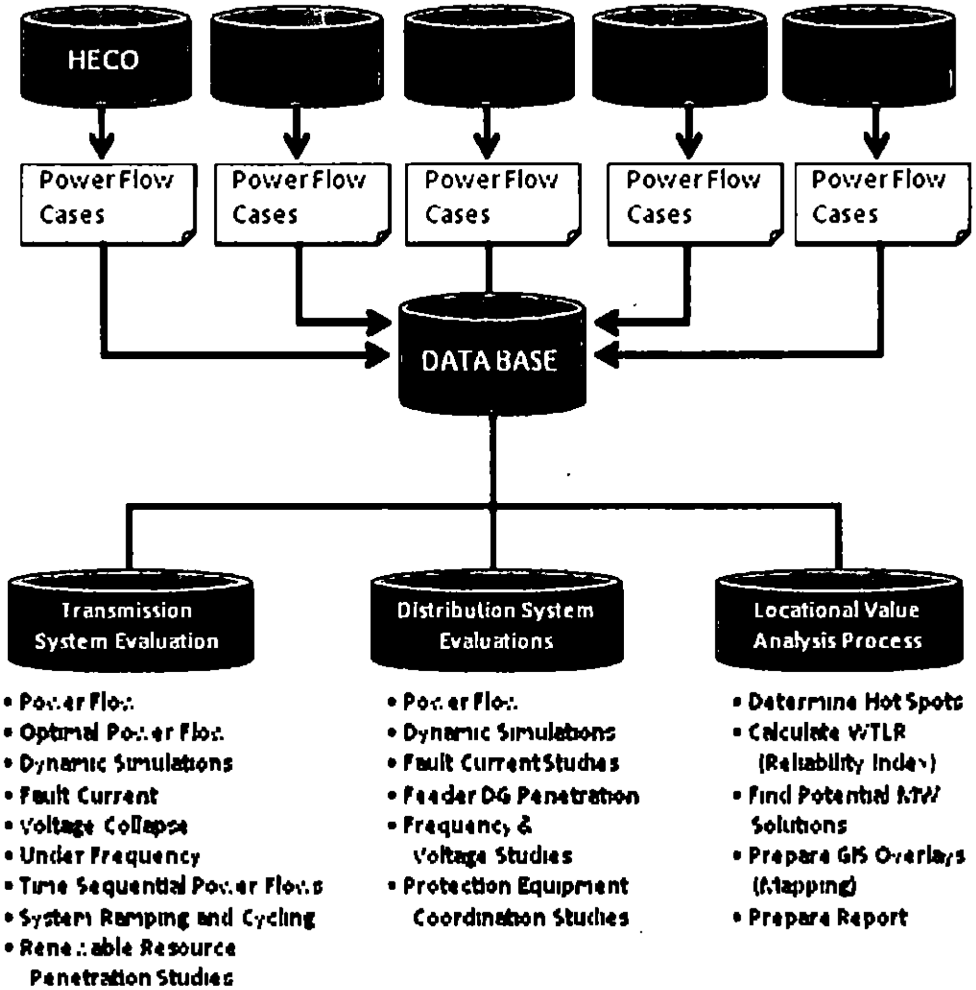
The evaluation of renewable resource penetrations on the HECO system is divided into distribution and transmission analysis. The potential impacts and penetration limits are different for each grid but at the same time overlap each other. The common elements to each analysis are:

- The need for a resource queue to record and track requests from developers to install new generation
- The ability to maintain a detailed data-base on installed renewable facilities
- The ability to maintain up-to-date planning models to evaluate new projects
- The development of a transparent methodology for developers, government agencies, utilities and others to understand the evaluation process that is accepted and used in other states

HECO will be developing a more centralized process to monitor the interconnection applications from the various resource contracting mechanisms. This information will serve to continually monitor the status of the interconnection work in process and identify areas for potential efficiency consolidations. In addition, the status of projects either in process or completed can provide regular feed back for conducting short range and long range system planning and operating studies.

The last issue is the development of the type of studies for evaluating transmission and distribution resource interconnection requests. The proposed methodology depicted in Figure 7 shows that there will be three main study areas: Transmission, Distribution and Locational Value Analysis. In the transmission analysis, there is a list of studies that may need to be completed for each new interconnection request and for a HECO transmission and generation system study. Under the distribution analysis, there is also a list of potential studies that may be required for a new renewable resource and for a HECO distribution system wide study. The last section is the locational value analysis which lists the various steps. In this section, HECO will update the RPS and FIT penetration alternatives and develop a list of beneficial areas and potential system upgrades.

**Figure 7 Proposed Methodologies for HECO to Evaluate Resources**




HECO should develop the distribution and transmisison data sets to be used in one of three simulation model formats. These simulations models are SynerGEE, Power World and PSS/E that will be used to simulate the 12 kV, 46 kV and 138 kV systems. The time increment for studies can range from seconds to hours, depending on the type of analysis needed and the availability of data. Each of the simulation models is briefly described later.

## *4.1 Application of Locational Value Analysis*

BEW assisted HECO in completing a RPS study. The study evaluated the renewable energy requirements to meet energy targets from 2010 to 2030. HECO determined the renewable options that would be available each year, the penetration energy targets and the general location of the renewables. BEW then completed the transmission locational value analysis to determine the transmission benefits of each option and a list of potential transmission upgrades needed to facilititate renewable development. The study did not include distributed generation under the FIT program. The study will need to be upgraded as potential DG penetration values are determined.

## *4.2 Distribution Planning Approach to Evaluating New Projects*

HECO is using the SynerGEE distribution planning model and the BEW is using the Power World transmission load flow simulation model to simulate the 12 kV and 46 kV HECO systems. There are several study areas in the distribution planning area:

- Initial Distribution System Study
- Individual DG resource study or Individual Feeder Study when the 15% Penetration is reached
- Periodic Distribution System Updates

Under this FIT docket, HECO will have information regarding penetration level of individual distribution feeder. Several of the existing feeders are close to or exceed the proposed level. HECO needs to complete detailed feeder studies once the 15% penetration is reached in order to determine the potential system impacts and reliability issues that could be determined from this initial study. After completing the individual feeder studies, HECO should complete a detailed distribution system study. A list of the potential study cases are shown in Figure 7.

For a new FIT project, HECO will first simulate the distribution model without the proposed project. The simulations will be done under steady state and then contingency analysis. HECO will also consider the switching routines and protection equipment coordination in the analysis. A list of potential study areas are shown in Figure 7. HECO will then add the proposed project and complete a similar analysis. The results of the studies will be analyzed to determine if the proposed project will have a benefical or negative impact on the feeder.

As each feeder approaches the feeder limits as discussed earlier, HECO will conduct studies to determine if additional facilities can be interconnected on the feeder. The facilities installed under NEM also need to be evaluated since these facilities add more variability of resources on the feeder. The combined variability of operation from the NEM and DG facilities will determine the maximum penetration.

The Power World data sets of both the 46 kV and 138 kV systems will then be used to evaluate the impact of the proposed projects on system reliability, ramping, frequency, and other system security issues.

## 4.3 Transmission Planning Approach to Evalating New Projects

All renewable resources installed on the distribution system impacts the transmission system and genereating plants. In addition to the distribution installed facilities, there will be new, larger renewable resources from wind, solar and hydro installed on the transmisison system to meet the mandated RPS requirements. All of these resources must be studied on the transmisison system.

The two models used to evaluate the transmission and generation impacts are PSS/E and BEW's Power World. The PSS/E model simulates the 138 kV system, 46 kV loads and the generating plants. This model will be used to study the dynamic stability, fault current and other reliability issues in detail. The General Electric PSLF may also be available from consultants to use in studies. The Power World model simulates the 46 kv and the 138 kV systems. By having the 46 kV system modeled in both the distribution and transmission models, the common database provides consistent results across the entire HECO system. Both models will be used to study the response of the generating plants to respond to outages on the system and to dispatch to follow the variability of renewable resources. Figure 7 lists the potential study areas.

## 4.4 Explanation of the Locational Value Analysis Methodology

The methodology for evaluating the transmission benefits of renewable resources on the HECO system is based on the Aggregated Mega-Watt Contingency Overload (AMWCO) index, developed under the California Energy Commission's Public Interest Energy Program (PIER) program for evaluating renewable penetrations and reliability benefits. The methodology was first developed in the 2005 Locational Value Analysis of Renewable Technologies Study (SVA) and enhanced in PIER Intermittency Analysis Project (IAP). The SVA methodology was later changed to the Renewable Transmission Benefit Ratio (RTBR) analysis.

In the RTBR and IAP, several analytical tools are developed to evaluate the transmission system performance under various scenarios, renewable mixes, and intermittent resource production levels. An analytical approach to transmission system expansion requires the simulation of the transmission system under a set of contingencies. Typically, transmission systems are built with redundancy to withstand severe contingencies without losing load or experiencing security violations such as transmission overloads. The effects of contingencies are tabulated to determine useful metrics to evaluate transmission grid reliability.

For each scenario, a set of N-1 contingencies produce a list of overloaded transmission elements. The study considers all contingent outages of single transmission lines, single transformers, and single generators (n-1), and measured contingency overloads only on non-radial transmission elements in California. The simulations incorporated linear approximations of post-contingent conditions to reduce simulation runtime. The linear approximations use flow sensitivities to estimate changes in real power flows and did not evaluate reactive power flows.

The percent overload of the element is weighted by the number of outage occurrences. For a particular line outage, or contingency there are overloaded elements. Each overload element percentage is subtracted by 100% and summed. This value is multiplied by the line rating (MVA) to achieve the AMWCO value for that line outage. All of the individual AWMCO values are summed to achieve a System AMWCO value. The delta AMWCO is the difference between the system AMWCO for the base case and each new renewable case. Delta AMWCO is therefore a transmission reliability index, with a unit of megawatts.

A negative delta AMWCO, a decrease in the AMWCO, indicates an improvement in transmission reliability. The larger the negative delta AMWCO, the more beneficial the transmission element is to the transmission system. For example, if 10 MW of CHP reduces the base AMWCO from 1,012 to 1,000, then the delta AMWCO is -12, and there is a benefit to the system. Comparing delta AMWCO's is difficult since the numbers vary considerably.
If the delta AMWCO is divided by the megawatt of CHP, then an index per MW injected can be determined. The Renewable Transmission Benefit Ratio (RTBR) is the change in System AMWCO per MW of CHP generation. Thus RTBR measures the impact of the CHP resource on system security. Negative RTBR indicates an improvement in system security.

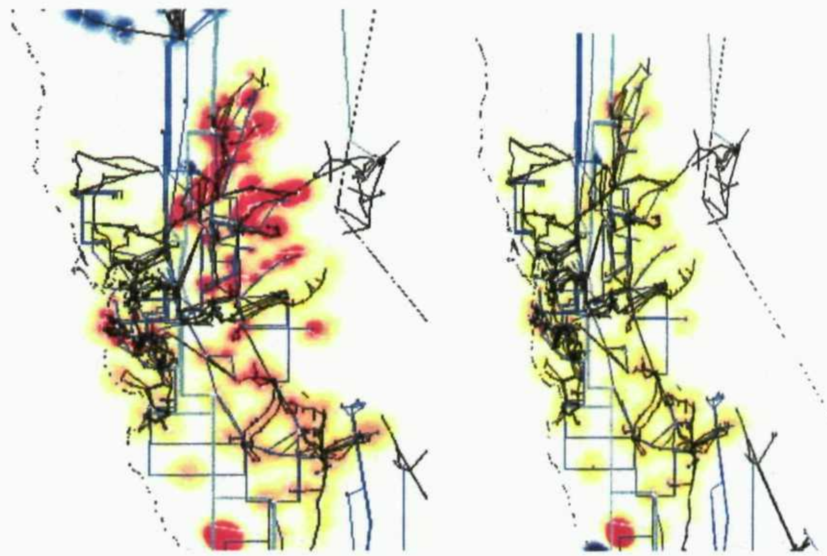
$$RTBR = \frac{AMWCO_{renewable} - AMWCO_{base}}{MW_{renewable}}$$

In the above example, if the CHP megawatt is 10 MW, the AMWCO per MW is – 1.2. A RTBR of -1.2 means that 1 MW of new CHP generation on the system is likely to reduce 1.2 MW of the overall system overloads in the system.

In the California example below (Figure 8), the left figure shows the 2007 transmission line overloads or "hot spots". The red areas are overload areas where the injection of distribution generation would have the greatest value to reducing transmission overloads and congestion. The yellow areas are the second best location for new generation. The blue areas are congested areas that any additional generation would only increase congestion and should be avoided.

The left figure shows the results after the injection of 1,000 MW of distributed PV. As shown, the majority of red shaded areas have been replaced with yellow shaded areas. This indicates that the strategic injection of distributed PV reduced the congestion areas significantly. While the yellow areas are not totally cleared, the remaining red and yellow areas can be studied using additional renewable resources such as wind, solar, geothermal and biomass, in this example.

**Figure 8: California Impact of Higher Penetration of PV**



The RTBR methodology has been used in the CEC Intermittency Analysis Project (IAP), the CEC Northern California Regional Integration of Renewables (RIR), the CPUC Self Generation Incentive Program to evaluate the continued value of distributed generation, the CEC Combined Heat and Power (CHP) Study that evaluated the RTBR value and emission reduction value of small distributed generation and finally the Southwest Power Pool (SPP) for strategically locating renewable resources. The methodology is extensively used by BEW in siting of new potential renewable resources that provide transmission grid benefits to the utilities.

Each renewable location has a different RTBR value that is dependent on its size, location, number of contingency outages and connected voltage. Some locations provide an immediate reduction in the RTBR with little or no transmission upgrades. Other renewable locations cause higher line overloads and therefore higher positive RTBRs unless upgrades are made. Transmission upgrades can reduce the RTBR but cause the overall capital costs to increase. The increase in cost could make the renewable project non-cost effective or delay the renewable commercial date to a period that is unacceptable. Finally, other locations create such high line overloads and possibly unsolvable cases that the sites are not feasible to inject renewable resources.

The RTBR and IAP methodologies were developed as input into the formation of the energy policy. There are four basic components in forming energy policy. The first is to define the characteristics or parameters of renewable resources. With respect to load and RPS requirements, what characteristics are needed from available resources. The next component is the impact of renewable resources on the transmission and distribution grid. The third is the development of the GIS locations so that overlays between load centers, renewable resources and transmission congestion zones can be prepared. The last component is the defining of public benefit parameters. Each renewable resource location can provide public benefits. These benefits could be job creation, carbon emission reductions and local tax base, for example.

More information on AMWCO can be found in the Energy Commission's report "Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets, June 2005, CEC-500-2005-106".

# 5. DESCRIPTION OF THE TRANSMISSION AND TRANSMISSION SIMULATION MODELS

The following description of the simulation models were taken from each company's public website.

## SIEMENS PSS®E Transmission System Analysis and Planning

PSS®E is the premier software tool used by electrical transmission participants world-wide. The probabilistic analyses and advanced dynamics modeling capabilities included in PSS®E provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSS®E is the standard Siemens offering for electrical transmission analysis that continues to be the technology of choice in an ever-growing market that exceeds 115 countries.

Since its introduction in 1976, the Power System Simulator for Engineering tool has become the most comprehensive, technically advanced, and widely used commercial program of its type. It is widely recognized as the most fully featured, time-tested and best performing commercial program available.

PSS®E is an integrated, interactive program for simulating, analyzing, and optimizing power system performance. It provides the user with the most advanced and proven methods in many technical areas, including:

- Power Flow
- Optimal Power Flow
- Balanced or Unbalanced Fault Analysis
- Dynamic Simulation
- Extended Term Dynamic Simulation
- Open Access and sdPricing
- Transfer Limit Analysis
- Network Reduction
- **A timely tool for addressing key**
- **reliability concerns in power systems,**
- **including:**
- Multiple contingency analysis
- (N-1-1; N-2; N-1,N-1)
- Cascading failure vulnerability analysis

- Automatic application of mitigation
- strategies
- Development of probabilistic reliability
- indices.
- **Simulates all simple and complex**
- **fault types, including:**
- Three-phase (3PH) faults
- Single-line-to-ground (LG) faults
- Double-line-to-ground (LLG) faults
- Line-to-line (LL) faults
- IEC 60909 calculations
- ANSI standard calculations.
- **Rapid-fire expansion of analytical**
- **content:**
- Incorporation of major analytical
- enhancements
- Staying abreast of regulatory reliability
- requirements
- Has the right tools to study new
- technologies.
- **Ideally suited to solving the challenges**
- **of all power system regulatory**
- **environments, including:**
- Transfer capability investigation
- Voltage collapse analysis
- Reactive power scheduling
- Ancillary service opportunity cost
- assessment
- Impact assessment
- Congestion analysis
- Location-based marginal cost
- assessment.
- **A leader in standardized data**
- **exchange, including:**
- PSS®E data sets are comprehensive and
- include robust planning models
- Proprietary file structure serves as a
- standard for exchange around the
- world
- A leader in embracing Common
- Information Model XML file exchange
- for increased model exchange accuracy
- across vendor platforms. Rich
- automation lets you take control!
- Provides tools for development of usercustomized
- models
- Permits user-specified execution and
- reporting.

## POWER WORLD CORPORATION'S POWER WORLD SIMULATOR

PowerWorld Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems of up to 100,000 buses.

**Simulator Customizations**

PowerWorld offers several optional add-ons to extend Simulator's analysis capabilities:

Optimal Power Flow
We have developed an linear programming based optimal power flow package. Simulator OPF, an optional add-on to the base Simulator package, is ideally suited to determining how to mitigate constraints in the most economical fashion, and to report the cost of enforcing line constraints.

OPF Reserves
OPF Reserves extends the power of the OPF and SCOPF tools to modeling of simultaneous energy and ancillary services reserve markets.

Security Constrained OPF (SCOPF)
The Security Constrained Optimal Power Flow tool, an optional add-on to the base Simulator package, is an extension to Simulator OPF used to achieve an economical operation of the system while considering not only normal operating limits, but also violations that would occur during contingencies. The SCOPF changes the system pre-contingency operating point so that the total operating cost is minimized, and at the same time no security limit is violated if contingencies occur.

Available Transfer Capability (ATC)
We have developed an extremely fast tool for calculating ATC. Simulator ATC allows you to determine the maximum MW transfer possible between two parts of the power system without violating any limits. This is the same calculation commonly performed by system operators or market operators.

PVQV Curve Tool
Simulator PVQV helps fill the industry's need for a user-friendly planning-mode tool for analyzing voltage stability and security that is flexible, highly graphical, and easy-to-use. This tool was previously known as Simulator VAST.

Simulator Automation Server (SimAuto)
Using SimAuto you can launch and control PowerWorld Simulator from within another application, thus enabling you to access the data of a Simulator case, to perform defined Simulator functions and other data manipulations, and then to send results back to your original application, to a Simulator auxiliary file, or to a Microsoft® Excel spreadsheet. The Simulator Automation Server acts as a COM Object, which can be accessed from various Windows-based programming languages that support COM compatibility. Examples of programming tools with COM compatibility are Borland® Delphi, Microsoft® Visual C++, and Microsoft® Visual Basic, just to name a few.

Transmission Line Parameter Calculator (TransLineCalc)
The PowerWorld Transmission Line Parameter Calculator (TransLineCalc) is a tool designed to compute the most important characteristic line parameters given the type of conductor and the tower configuration of a three-phase overhead transmission line. The TransLineCalc tool is completely integrated with Simulator, which means that TransLineCalc can be launched from Simulator, and then the results can be passed to Simulator.

## GENERAL ELECTRIC PSLF SOFTWARE

### Fast, Accurate, Customizable Simulations

As the number of power transactions increases, new supply patterns are pushing transmission systems to the limits. This increased line loading results in reduced margins and a significant challenge to system reliability. At the same time, system planners are seeing more volatile dispatch patterns. This trend will continue as market prices affect the demand for power in a competitive market.

All of these factors point to the need for increased accuracy in modeling, and greater productivity in system planning. GE Positive Sequence Load Flow Software (PSLF) can help utilities achieve these goals. This full-scale program is designed to provide comprehensive and accurate load flow, dynamic simulation and short circuit analysis. Using this tool, engineers can analyze transfer limits while performing economic dispatch. PSLF is ideal for simulating the transfer of large blocks of power across a transmission grid or for importing or exporting power to neighboring systems.

PSLF is a suite of analytical tools that can simulate large-scale power systems up to 60,000 buses. For ease of use, the data are organized in sensible terms, such as nameplate values, rather than per-unit modeling parameters. Since PSLF has its own fully configured programming language, users can build new models that interact with models within the program, perform post-processing and construct macros that automate execution of repetitive simulations and generate reports.

## GL-GROUP SYNERGEE DISTRIBUTION SOFTWARE

SynerGEE can perform detailed load modeling and a host of useful analyses on radial, looped and mesh network systems comprised on multiple voltages and configurations. All analyses rest on the solid load-flow foundation that makes SynerGEE the most reliable distribution analysis tool available.

Circuit analysis with robust and technologically-advanced tools can safeguard your system through enhanced network performance, extended asset life and increased profitability. GL offers a comprehensive collection of power system analysis tools to support your data needs, including custom application development and product implementation in enterprise systems and processes.

## 6. REFERENCES

"Interstate Generation and Delivery into California form the Western Energy Coordinating Council States", California Energy Commission, April 2005, CEC-500-2005-D64D

Strategic Value Analysis for Integratig Renewable Technologies in meeting Target Renewable Penetrations, CEC 2005, CEC-500-2005-081

"Intermittency Analysis Project, CEC 2007", CEC-500-2007-081

Attachment 2

Evaluation of Distributed Generation
Hawaiian Electric Companies

**Introduction to Distributed Generation on the HELCO, MECO and HECO Systems**

The HELCO system has a large amount of distributed generation (DG), mostly PV, with significantly more projected in the near term. HECO penetration level of DG is small at this time but significant expansion is anticipated in the next two years.

The reasons for the increase in DG in the past two years for HELCO are a combination of factors, but primarily driven by the utility's energy costs.

It is a known issue in the utility industry that numerous system reliability impacts occur at high penetration of distributed generation, especially when connected according to present industry guidelines which are designed for low-penetration systems for the purpose of minimizing negative feeder impacts. However for the North American interconnected utilities, the issues are for the most part theoretical, as penetration levels remain small relative to the overall interconnection. DG impacts on the North American interconnections are primarily steady-state (effects on the power flows and voltages), particularly for systems such as Electric Reliability Council of Texas (ERCOT) where the system is already constrained by other generation (such as wind). These steady-state impacts are exacerbated by the fact that planning of the distribution system is not well coordinated with planning of the transmission system for the present organization of most power systems on the mainland; because the distribution systems are owned and operated by separate companies.

The HELCO system, with its high existing penetration of distributed PV, provides a case study for overall system impact issues that can occur at high penetration of DG relative to the overall system size. The HELCO system also has individual circuits with up to 62%% penetration In addition to the issues that come with DG in general, much of the generation is variable PV. HELCO already has a very high amount of variable generation from hydroelectric and wind resources on the transmission system, which creates issues and uncertainties for real-time balancing and frequency control. The impact of variability from the distributed PV is complicated by the fact that the typical capacity factors, production profile, degree of variability and correlation between sites is not known and there is nearly no visibility of production from these sites for the system operator. At the levels of DG penetration on the HELCO system significant dynamic stability effects on the power system are encountered, which are more complicated to analyze than steady-state effects.

**Amount of DG on the HELCO system**

The table below is the current and forecasted status of DG on the HELCO system as of December 31, 2009. HELCO's existing total is 9.1 MW, which comprises 4.68 % of the 2009 system peak of 194.6 MW. However, most DG is PV and therefore is producing during the day peak. Using the average weekly high day peak, the total existing DG is at

5.52%. Further, many projects are projected for 2010. Based on projects submitted to HELCO engineering as of the end of 2009, there would be 17.1 MW of DG, of which nearly 14.4 MW will be PV, with another .36 MWof wind and hydroekectruc. Several additional applications and requests for DG connections come in weekly. The projected additions would take the DG to 8.77% of the system peak, 10.34% of the average weekly high day peak. Most of the existing and all of the projected DG is variable (non-firm). If the distributed PV is near capacity, the total MW contribution will be comparable to a typical loading of the larger transmission connected generating units.

**HELCO DG Summary**

**As of 12/31/09**

| Type of Agreement | Variable PV_Wind_River kW @ 59.3 Hz | Variable PV_Wind_River kW @ 57.0 Hz | Variable PV_Wind_River Total | Non-Variable Diesel_Propane Fuel Source | TOTAL |
|---|---|---|---|---|---|
| NEM Generation | 2360.73 | 1077.40 | 3438.13 | | 3438 13 |
| No Sale | 1860.00 | 1305 00 | 3165 00 | 2345.00 | 5510.00 |
| Schedule Q | 167 70 | 0 00 | 167 70 | | 167 70 |
| Planned DG | 145 78 | 7805 00 | 7950 78 | | 7950.78 |
| TOTAL Existing | 4388 43 | 2382 40 | 6770 83 | 2345 00 | 9115 83 |
| TOTAL Existing+Projected | 4534 21 | 10187 40 | 14721 61 | 2345 00 | 17066.61 |
| Based on 194.6 MW Sys. Peak | % @ 59.3 Hz | % @ 57.0 Hz | % Total Variable | % Fuel Source | % TOTAL |
| TOTAL Existing | 2 26% | 1.22% | 3 48% | 1 21% | 4 68% |
| TOTAL Existing + Projected | 2.33% | 5 24% | 7.57% | 1 21% | 8 77% |
| Based on 168.2 MW Avg. Day Peak | | | | | |
| TOTAL Existing | 2 66% | 1.44% | 4.10% | 1 42% | 5 52% |
| TOTAL Existing + Projected | 2 75% | 6 17% | 8 92% | 1 42% | 10 34% |

Existing projects are online. Projected projects based on applications and/or preliminary designs received by 12/31/09

**Figure 1Table of HELCO DG Resources**

## Preliminary Studies and Identification of DG-related Issues

HELCO recognized that the changing generation mix on its system, due to the anticipated addition of significant DG and addition of large wind resources changed the HELCO power system characteristics. HELCO commissioned a series of system studies to investigate possible impacts of the shift in generation using the consultant Electric Power Systems, Inc (EPS). The first of the studies included an initial assessment of adding large amounts of DG along with the variable wind, and was completed in December 19, 2005. This study identified several modifications to operational practices and follow-up work and the fact that HELCO's system stability was definitely affected by changes in the generation mix. Several of the issues raised had to do with the impacts due to displacement of conventional generators, and accommodation of highly variable generation, rather than being specific to distributed generation. With the addition of two large wind projects in the near-term, the follow-up system studies in the next few years focused on the issues that pertained to integration of these wind resources.

In early 2008, as high costs and programs such as Net Energy Metering (NEM) saw an increase in the anticipated DG penetration on the HELCO system, a task force was created to identify areas of concern and study. The following is the summary of this initial task force effort.

As penetration increases, the protection requirement becomes more complicated:

- There is increased magnitude of distribution fault current created by distributed generation. The impact depends on the type of generation. Increasing the magnitude of fault current may exceed the interruption rating of devices, exceed equipment or conduction ratings and change fusing types needed.
- The purpose of typical distribution protection is to isolate the fault. The change in current flow on the distribution circuit can cause miss-coordination of the protection schemes, causing the protection to isolate either too large a section or the wrong section. This will lead to difficulty in locating the actual fault cause and extend outages, due to poor sectionalizing.
- The utility overhead circuits are normally designed to reclose quickly to restore power faster due to temporary faults to maintain feeder reliability however, with high penetration of DGs the fast automatic breaker reclosing must be disabled.
- For maintenance and restoration, circuits are transferred to adjacent substations. If there is DG on that circuit, this may cause problems, for example the transfer trip scheme will not work or other problems.

Voltage Regulation Practice will have challenges:

- The distribution system is a radial design and voltage regulation is normally accomplished through the use of the Substation Transformer Load Tap Changer (LTC). The LTC control presently uses a scheme (R and X compensation) which will become fooled by reverse flows, causing the LTC to operate incorrectly which would cause voltage problems. The present scheme will have to be modified and it is unlikely that regulation will be accomplished solely by use of the LTC, and requires additional distribution voltage control devices, when DG is added to the circuit.
- Existing distribution capacitors are fixed. The addition of DG on the circuit will require these capacitor banks to be switched according to the distribution voltage level.
- Voltage Regulators are used on long distribution circuits. (For example Punaluu to Pahala, Punaluu to South Point, Shipman to Keaukaha) and in some substations. These regulators can also misoperate and cause severe off-normal voltages for reverse flows that can be created by distributed generation.
- The distribution customers can be subject to voltage fluctuations due to rapid ramping of PV systems or any rapid change in power output. This should be

flushed out if an analysis is done for power fluctuation rate per Rule 14H. A solution is for the DG to provide voltage regulation.

- The various devices on the distribution system need to work in concert. At this time, there is no communications infrastructure as would be necessary to coordinate control or monitor these distribution voltage control devices and DG.
- DG units are not required to regulate voltage, if installed under the IEEE 1547 requirements.
- Circuits can be transferred to other substations, which may cause problems on the new circuit, unless DG is forced offline for out of normal configurations.

Issues Associated with Islanding:

- Rule 14H specifies that larger DG units require more expanded under frequency and more stringent under voltage ride through settings. More stringent ride-through requirements may also be necessary due to the cumulative effect of DG lost during transmission faults on the system. A bigger ride-through window increases the likelihood that DG units remain connected when the distribution circuit opens, creating islanding. The solution is transfer trip based on distribution circuit status, which requires high speed communication to direct trip the unit.
- Distribution substations are tapped off of transmission and sub-transmission lines, in such cases the DG can island with the distribution substation and transmission line. Addressing this may require sophisticated transfer trip schemes (distribution tripping coordinated with the transmission breakers) and equipment upgrades to handle possible voltage conditions and current that could be created during the islanding (lightening arrestors, PT's – any single phase or line to ground equipment).
- Anti-islanding schemes for multiple DG on a common circuit need to be compatible with each other.
- If the DG suddenly islands with a line to ground fault with a small load (relative to the DG), creating a lightly loaded island, the potential exists for ferroresonance and load-rejection overvoltage, subjecting customers to grossly out of range voltages.

Grounding and over-voltages due to faults:

- HELCO distribution is typically designed such that the ground source is at the substation. When the substation distribution breaker opens, this ground source is isolated from the distribution feeder. Adding DG to this distribution circuit will result in over-voltages along the distribution line and the DG facility during a single-line-to-ground fault when the substation distribution breaker opens. Refer to attached "Interconnection Study for Orchid Hotel" by Power Technologies Inc which was completed December 9, 2002.
- If the DG facility neutral is not effectively grounded or is ungrounded this will result in potentially damaging overvoltages on the unfaulted phases at the DG facility. Refer to attached paper by Nova Energy Specialists on "Quick Discussion of Ground Fault Overvoltage Due to PV Inverters" dated September 17, 2009.
- If the distribution substation connects to a transmission or sub-transmission line, clearing the transmission line may also create loss of ground source at the

transmission level, creating the same problem on the transmission system for a line to ground fault (fed by the DG sources on the distribution circuits tapping into that transmission line). Affected equipment would include lightening arrestors and line side potential transformers that are connected line to ground.

System Issues:

- Not all the relay protection trip settings for off normal voltage and frequency conditions (i.e. 81 O/U, 27 or 59 settings) are known for the DG on the system. It is suspected that all the generating facilities have the same settings as IEEE 1547 30KW and less.
- For generation less than 30 kW, the settings required are based on IEEE 1547 which is not meant to address high penetration levels of DG, and thus the under voltage and underfrequency settings are not well coordinated with HELCO relay settings. There is provision to require different settings for larger DG and where DG penetration exceeds 10% of the circuit.
- Per IEEE 1547, the DGs with 30kW or less capacity will trip at 59.3 Hz. HELCO underfrequency load shed (with minimal time delay) starts at 58.8 Hertz and down to 57.7 Hertz which involve approximately 69% of the Big Island's load during peak load conditions. This mis-coordination of the DG and the utility's underfrequency settings will require the utility to trip even larger amounts of load in order to restore the frequency back to 60.0 Hertz. Recently HELCO had a condition where the wind farm ramped off to 59.3 Hz before fast start generation could come on-line. Present projection is DG (NEM) up to 4% which would be 8 MW based on the 2007 peak. Loss of 8 MW of generation in addition to the wind farm ramping off. HELCO would have lost customers due to under-frequency load shedding.
- Per IEEE 1547 under voltage trip settings, DG will be prone to tripping for normally cleared faults on the transmission system.
- Because of the large amount of generation that will be due to solar, the underfrequency scheme may have to be a hybrid to allow for a day time scheme and a night time scheme resulting in large change in demand at each circuit which does not conform to the typical demand use pattern. Because of the variability of the generation source, the scheme may be difficult to coordinate.
- HELCO's distribution system is radial in design and voltage regulation is normally accomplished via the use of the Substation load tap changer (LTC) or voltage regulators on the distribution line

Recommendations and conclusions from this analysis:

Modification to the Distribution system:

- The distribution breakers will block fast closing if the distribution circuit is still energized. Normally this is done with a an undervoltage relay (Device 27) or other live line check devices.

- A distribution communications system that would be used to provide data for monitoring and control is necessary for high penetration; however we have not identified a commercially available, cost-effective technologies for wide-scale implementation of monitoring and control of numerous small resources.

- LTC control could become a pure voltage regulator rather than the present scheme (R or X line compensation). In some cases, a reverse power detection LTC controller would have to be installed at substations where there is more generation than load.
- Grounding transformer installation in the substation or at the DG facility to limit voltage rises on the unfaulted phases. Refer to attached "Interconnection Study for Orchid Hotel" by Power Technologies Inc which was completed December 9, 2002 and Nova Energy Specialists on "Quick Discussion of Ground Fault Overvoltage Due to PV Inverters" dated September 17, 2009.
- Direct Transfer Trip (DTT) protection with a licensed radio communication link from the DG facilities to the substation in order to trip the DG offline before the substation breaker opens. Refer to attached "Interconnection Study for Orchid Hotel" by Power Technologies Inc which was completed December 9, 2002.
- Convert existing capacitor banks on the distribution system to switchable units that will detect over voltage and trip capacitors offline using vacuum switches.

Requirements for interconnected DG at High Penetration:

- Future DG providing voltage regulation control based on the secondary voltage level to which they are connected. The controls would need to be tuned to the grid voltage response. There may have to be two control loops based on the voltage and the power output.
- Future DG would preferably have a droop response (settable) and contribute to system frequency regulation based on the local frequency measurement. This can be accomplished via four quadrant inverters and load resistors installed.
- The DG system would preferably have transfer trip capability based on a reliable communication link from the DG facility to the substation. This would allow the DG to separate upon loss of the signal, via a direct transfer trip The communications method could potentially be designed to handle situations whereby the circuit is switched to an alternate substation (i.e.; not a fixed system) – if not the design must accommodate possible reassignment to alternate substations during restoration and maintenance.

Possible Required System changes:

- Ehanced under frequency scheme
- Investigate means of monitoring of DG to system operations and to use for trip schemes. For monitoring, the information does not have to be as fast as protection and can have some latency, but is necessary for load forecasting, assessing variability, and evaluating impacts on operating reserves. For transfer trip, high-speed is necessary.

Recommended System Studies:

- Consultant to examine the changes to the Under Frequency load shedding scheme as a result of having a large difference in generation between day time and night time. Enhanced under frequency scheme
- Consultant to examine the effects of distribution faults and transmission zone 2 faults on the system voltage.

The issue of nuisance trips became the most immediate and was the focus of the near-term efforts. Some changes to underfrequency load-shed were performed as well with a change to the underfrequency load-shed scheme implemented in 2009.

**Reliability Impact of Aggregate Loss of Distributed Generation (Nuisance Trips)**

In order to avoid potential circuit problems, it has been the practice of utilities in the United States to set up distributed generation to trip during off-normal frequency and voltage conditions. This practice is in accordance with IEEE 1547 recommendations, as tripping DG during off-normal voltage and frequency conditions is a relatively simple and inexpensive means to avoid potential power quality problems associated with unintentional islanding. Unintentional islanding can occur on a distribution circuit with installed DG if the circuit is opened and creates an island with the circuit load with the distributed generator. The typical IEEE 1547 trip settings are intended to ensure the DG disconnects when the circuit becomes isolated. As noted in IEEE 1547, the settings are designed to protect circuits, but do not consider system impacts. The fact that this approach will result in reliability impacts due to nuisance tripping when the penetration of DG is high, is understood in the industry, but in North American power systems is only a theoretical issue as penetration is low relative to the interconnected power system.

On the HELCO, MECO and HECO systems, the typical IEEE 1547 trip settings represent voltage and frequency deviations that commonly occur during generator contingencies and transmission system faults and other transmission disturbances. As discussed in the System Balancing and Frequency Control report, all imbalances of production and supply on the autonomous island power systems result in a change in system frequency. When distributed generation represented only a very small amount of generation on the system, the loss of the distributed generator did not present issues for the power system.

At this time, the level of DG penetration on the HELCO system is such that the aggregate loss of creates a noticeable and significant change in system frequency during voltage and frequency disturbances compared with system behavior prior to the connection of the large amount of DG. The impact loss of the projected amount of DG on HELCO is undoubtedly very significant, and has not been completely analyzed. HELCO, with the highest penetration of DG of the power systems on Maui, Oahu and Hawaii, has taken the lead on examining the impact of nuisance tripping on its power system.

All the distributed generation (DG) on the HELCO system initially installed (prior to early 2009) in accordance with the typical IEEE 1547 frequency and voltage trip settings. At the higher penetrations of DG that began to be seen in late 2008, under frequency ride through and the under voltage ride through became a particular concern as the frequency impact from the loss is non-trivial.

The possible aggregate loss of DG during underfrequency was of the most immediate concern because it poses a significant risk. A frequency decline will be experienced simultaneously by all connected DG, and result in loss of all connected DG, if all have similar trip settings. An aggregate loss of generation during low-frequency worsens the existing low-frequency condition and in the most extreme case contributes to cascading outages and system failure. Thus this was the first issue to be investigated in detail.

**Analysis of the Impact of DG on the HELCO System during Generator Contingencies (Underfrequency Tripping)**

The HELCO system is currently at risk by the aggregate loss of distributed generation (DG) connected according to minimal IEEE 1547 guidelines for off-normal frequencies due to generation/load imbalances. This is due to the limited ride-through capability of a large portion of the DG, due to conservative frequency trip settings at (59.3 Hertz for 0.16 seconds). Imbalances resulting in frequencies of 59.3 Hertz and below commonly occur on the HELCO system due to of loss of generation, loss of transmission, wind down-ramps and system faults.

Although there are provisions in IEEE 1547 to allow more stringent Under Frequency (UF) trip points for generation larger than 30 kW expanded frequency ride-through, until early 2009 such capabilities were not been required and the default trip point of 59.3 Hz was used. As a result, the majority of the DG connected to the HELCO system had an UF trip point of 59.3 Hz up until early 2009 when when the EPS study was commissioned when the utility experienced operating issues.

Frequency is the same throughout the power system, therefore if the system frequency drops below 59.3 Hz for 0.16 seconds, all the DG connected in accordance with the typical IEEE 1547 trip settings would trip off-line.

In late 2008, HELCO System Operations observed that during loss-of-generation events, more underfrequency circuits were being lost than would have occurred in the past for that level of generation. It was speculated that the aggregate loss of DG at low-frequencies may be contributing to a net loss of generation (original loss of generation + loss of distributed generation at 59.3 Hz) which resulted in a greater imbalance and possibly causing underfrequency. HELCO therefore commissioned a study by the consultants Electric Power Systems, Inc. These consultants are familiar with the HELCO system and specialize in dynamic and steady state analysis of island power systems.

In August 2009, Electric Power Systems Inc. completed the technical analysis, "HELCO Maximum Penetration of Distributed Generation Study", to determine the impact on system behavior of incremental amounts of DG with the 59.3 Hz trip point during underfrequency disturbances. These stability simulations required detailed modeling of the HELCO system dynamics such as rotational inertia, droop response, transient impedances, etc. The need for the dynamics data for loads and generators on the power system makes such modeling more complicated and difficult to perform accurately than standard steady state load flow simulations. While the study was being conducted, HELCO's system operations engineers estimated a level of DG connected with the typical trip settings at which customers would experience underfrequency load-shed, for generator contingencies which typically would not result in load-shed without the DG, to be 6.25 MW. This estimate was produced using the nominal steady-state frequency bias (which measures MW change on the HELCO system resulting in a tenth of a Hertz change in frequency). HELCO also contacted existing PV installers with a request to alter the trip settings for existing and planned sites to be aligned with the HELCO underfrequency load-shed, by remaining connected to 57 Hz, where possible. However, it should be noted that as HELCO is one of, if not the, first utility to require these setting modifications in the field, the actual behavior of inverters with such settings is not proven in the field. IEEE 1547 describes trip requirements in terms of minimum trip times rather than as an expected ride through. By extending the clearing requirements, it is our expectation that the inverter should continue to work through underfrequency until the trip settings, according to the technical experts we have consultant. However, this is unproven and it would be prudent to ensure that adjusting these settings does in fact result in the desired ride-through through field monitoring.

This impact study evaluated two sets of dynamic stability simulations in order to evaluate and quantify the impact of DG connected with typical IEEE 1547 trip settings (59.3 Hz for 0.16 seconds). The first set of stability simulations evaluated the system response to a loss of generation contingency (loss of Puna steam) under various base operating scenarios as the DG was incrementally increased. The second set of stability simulations determined the DG that could be added to the electric system such that for certain unit outages, the distributed generation would cause under-frequency load shedding during the generator contingency.

The first set of simulations showed that in all base cases studied, the DG did have an effect on the system response to the loss of generation event (trip of Puna). It created a lower minimum frequency (frequency nadir) and/or resulted in greater load loss (when the loss of DG pushes the frequency decline into the next stage of under frequency load shedding). As a result of the impact of underfrequency load shedding, the impact of the distributed generation on frequency is less pronounced for generator contingencies that result in Tier 1 or Tier 2 underfrequency load shedding without PV; up to the point where the load shed scheme is insufficient to halt frequency from the combined effects of the lost DG and the generator contingency. At some (unknown) level generation not coordinated with the underfrequency scheme in the frequency ride-through renders the underfrequency load-shed scheme ineffective and the system would fail.

Because of this complex dependency on the effect between the underfrequency scheme and the impact on frequency, the second approach was undertaken to further investigate the impacts of the DG connected with the 59.3 Hz trip point. This second approach investigated the point at which DG would probably cause underfrequency load-shedding, for conditions which did not shed load prior to the addition of the DG. This would set up a measure of the level of DG connected with the 59.3 Hz trip that measurable affected HELCO customer reliability. This logic was similar to that employed by the System Operations engineers in their in estimate of an impact level of DG based on the frequency bias of the system. However, the more thorough stability analysis showed that in fact, the method of using the frequency bias overestimated the amount of DG that could be taken without impacting underfrequency load shed. The error lay in using the steady-state frequency bias to produce the assumed of the frequency drop due to loss of generation, rather than the actual frequency drop which occurs in the dynamics time frame before the system frequency response has reached steady state. The study calculated the true amount of DG at which the frequency to decline increased enough to trigger underfrequency load shedding was quite small: consistently less than 2.5 MW, a number substantially less than previously estimated. The report found over various scenarios the amount was consistently 2.5 MW or less, depending again on the initial system conditions. As the DG on the HELCO system is primarily from PV systems which produce energy during the day time scenario (Base case 3 at 165.8MW), the amount of incremental PV generation of 2.0 MW combined with 9.8 MW of existing variable transmission generation resulted in the frequency dipping close to the first utility trip frequency load block. As explained in the report, changes in the base case (such as during Hill 6 overhauls) the effect of DG is more pronounced due to the resulting change in system frequency response without the usual base configuration. At the time of the study, there was 6.8 MW of DG on the system connected with the trip setting of 59.3 Hz.

**Conclusions and Actions Based On Analysis of Underfrequency Impact: Expanded UF Ride-through and Alternate Anti-Islanding Schemes**

The results of the study show that the HELCO system reliability has been negatively affected by the existing connected DG, as compared to what would have occurred in the absence of the DG. This impact is through lower frequency minimums and/or additional load-shed during loss of generation events. This supports the observations of Operations personnel that load-shedding is occurring for losses of generation that previously did not cause result in underfrequency load-shed. The impact is exacerbated during periods of few responsive units on the system and limited reserves in the "up" direction on the responsive units.

As a result of the findings, HELCO took immediate steps to change the frequency trip settings for existing and anticipated DG projects, where possible. In order to allow more variable generation on the system, HELCO was successful in converting 2.4 MW of variable distributed generation from 59.3 hertz to 57.0 hertz reducing the aggregate variable generation with frequency set-points of 59.3 hertz from 6.8MW to 4.4MW.

As of December 31, 2009, an aggregate of 4.4 MW DG is installed with these minimal settings (59.3 hertz trip at 0.16 second time delay), a level which based on the study results measurably and significantly negatively affects the system response to generator contingencies. HELCO will not be able to accept additional variable generation units with the fixed 59.3 hertz set-points.

To ensure better coordination with the system underfrequency scheme, the DG underfrequency trip set point for all new installations will be set to 57.0 Hz with a minimum time delay of 300 seconds; the maximum ride-through in accordance with IEEE 1547.

It should be noted, however, that this ride-through setting differs significantly from that required from the conventional units (which actually provide a stabilizing frequency response through droop and have no tripping on the basis of low-frequency alone), and transmission-connected wind resources (which must remain connected to 57 Hz, with instantaneous trip below 56 Hz). The impact of a high penetration of DG even with the expanded frequency ride-through must be further studied in order to ensure the system is appropriately designed (with consideration of the underfrequency load-shed scheme) to survive frequency disturbances to an adequate steady-state frequency.

As mentioned above, HELCO is one of, if not the, first utility to require these setting modifications in the field, the actual behavior of inverters with such settings is not proven in the field. By extending the clearing time, it is our expectation that the inverter should continue to work, according to the technical experts we have consultant. However, this is unproven in the field, and actual behavior needs to be evaluated through field measurements during disturbances.

Another issue is raised by expanding the under-frequency ride-through. DG must also avoid unintentional islanding that could occur with the feeder breaker opens. Expanding the ride-through capability means that frequency deviation is no longer an effective anti-islanding scheme. The DG shall detect the island and cease to energize the electric power system within 2 seconds of the formation of the island. Some examples of means to avoid anti-islanding DG with expanded underfrequency ride-through:

- The DG aggregated capacity is less than 1/3 of the minimum load of the circuit. A problem with this method can occur if demand on the circuit changes through events outside the utilities control. For example, if a large customer goes out of business the demand will decrease.
- The DG is certified to pass an applicable non-islanding test.
- The DG contains reverse power relays or other applicable relays.
- The DG contains other means for example direct transfer trip or some other approved scheme by HELCO.

**Under-Voltage Nuisance Trip Issues**

Similar to the concern over trips during underfrequency, the HELCO system is currently at risk by the aggregate loss of distributed generation (DG) connected according to minimal IEEE 1547 guidelines for under voltage disturbances due to grid faults. This is due to the limited ride-through capability of the DG, due to conservative under voltage trip settings. This is an issue presently under investigation by HELCO.

**Statement of the Under Voltage Problem**

According to IEEE 1547 recommendations, if the system voltage drops below 50%V then the DG must be cleared in 0.16 seconds. If the voltage is less than 88% V and greater than or equal to 50% V, the DG must be cleared in 2.0 seconds. The DG trip settings dictate that they must be cleared in 160 msec, or approximately 10 cycles.

**Table 1—Interconnection system response to abnormal voltages**

| Voltage range (% of base voltage[a]) | Clearing time(s)[b] |
|---|---|
| V< 50 | 0.16 |
| 50 ≤ V< 88 | 2.00 |
| 110 < V < 120 | 1.00 |
| V ≥ 120 | 0.16 |

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

The clearing time includes the time for the interrupting device to act, which means that the decision time to initiate may be far less than 10 cycles based on the interrupting device. Total clearing time for a zone 1 fault would typically be 5 to 7 cycles. In order to ensure clearing times in accordance with the 10 cycles, could mean that most of the less than or equal to 30 kW DG will trip with the zone 1 transmission clearing. This issue requires additional investigation. Unlike system frequency, voltage disturbances result in levels that vary throughout the network and therefore the impact can be specific to the location and proximity to faults.

**Recommendations to address Under-Voltage Nuisance Trips**

The need for significant generation sources on the HELCO system has been recognized. The conventional generating units are not permitted to trip offline on the basis of off-normal voltages alone, and are expected to remain on through primary and backup fault clearing. Due to equipment limitations of wind plants, a compromise position was established to allow under voltage tripping for these facilities. The under voltage ride-through required defines the voltage conditions under which the facility may trip, using the following language:

> The Seller's Facility, including its wind turbine generators, shall behave as follows during an under voltage disturbance ("V" is the voltage of any of the three voltage phases at the Point of Interconnection (PU stands for "per unit"):

| | |
|---|---|
| V ≥ 0.80 PU | Seller's Facility remains connected to the Company's System. |
| 0.75 PU ≤ V < 0.80 PU | Seller's Facility may initiate disconnection from the Company's System if "V" remains in this range for more than 2 seconds. |
| 0.00 PU ≤ V < 0.75 PU | Seller's Facility may initiate disconnection from the Company's system if "V" remains in this range for more than 600 milliseconds. |

Where possible, adopting the trip settings above for future DG should provide the ability to ride through the majority of transmission faults, but does require consideration of the impact on anti-island detection as discussed in the under-frequency trip analysis. HELCO recommends that a study be conducted to evaluate the impact of existing and anticipated DG on system dynamics performance through faults and disturbances due to the under voltage trip settings, to include recommended settings and/or system modifications to mitigate these impacts. The results will probably limit the amount of DG that can be tolerated within system areas. Unlike system frequency, voltage disturbances result in levels that vary throughout the network and therefore the impact can be specific to the location and proximity to faults. Similar to the issue discussed for under voltage ride-through, actual field performance with changed settings is not proven for most inverters. By extending the off-normal voltage range it is our expectation that the inverter should continue to work through off-normal voltages, according to the technical experts we have consulted. However, this is unproven in the field, and actual behavior needs to be evaluated through field measurements during disturbances.

**Additional System Impacts from DG**

In addition to the impacts from nuisance tripping, DG affects the system in other ways, as described in the preliminary list of DG-related impacts compiled in 2008 by the internal task force.

One of the key ways that DG affects the system is through its displacement of transmission generation through reduction in the apparent load. The cost impact of the DG on total production, and to consider cost of mitigation measures and displacement of production from other generating resources, has also not been evaluated.
Some of the cost and reliability impacts are similar to all types of variable generation, such as wind, connected to the transmission system: all variable generation contributes to system balancing and frequency control issues, and may also contributed to excess energy conditions depending on time of production and correlation of the variable resources with other variable RE resources.

There is a need to understand the impact of the DG, along with other anticipated generation changes, on system stability, including impacts system protection. There needs to be an assessment of the effectiveness of the underfrequency load-shed scheme, which could be complicated by the impact of the DG on circuit demand so that it decreases during the daytime hours, which does not correspond to the overall demand curve. The study should also asses any impacts from DG on the existing under voltage load shed scheme. System restoration could also be affected due to the automatic reconnection of non-controllable DG, and this needs to be evaluated and a plan for restoration developed.

**Need for Production Data for Distributed PV for Studies, Planning and Operations**

At this time, evaluation of the variable DG impacts is difficult due to the absence of data. At this time almost none of the existing variable DG is visible to the system operator. The typical capacity factors, variability, and correlation between sites are not known. Larger DG sites will be provided a SCADA/EMS interface, but at this time, there is not a commercially available, cost-effective means through which to communicate and control the numerous smaller DG throughout the system and bring the data to the System Operator through the SCADA/EMS system.

Through the Smart-Grid initiatives and other ongoing efforts, HELCO is investigating possible technologies for this purpose.

In the mean time, HELCO has implemented a project to collect information regarding solar PV production as a means to collect information about likely capacity factors, variability, and correlation between sites.

**Pilot Project for Monitoring PV and Estimating PV Production**

Presently HELCO has no data about the production from installed PV systems on the HELCO system. Trying to account for the amount of generation of the system is very important for planning and real-time operational decisions for system balancing and frequency control. In order to expand understanding of PV production and collect data on a real-time basis, HELCO has installed PV sensors throughout system at substations with SCADA/EMS interfaces. These sensors are being utilities to provide information about the available solar resources and estimate spot power measurements. HELCO has leveraged the existing SCADA system to obtain the largest number of site measurements as practical throughout the system. There are approximately 45 sensors presently connected to the system gathering data and the number will be increase as additional telemetry sites are added to the system. The spot measurements are provided through very small PV sensors that input directly into the Remote Terminal Unit (RTU). The RTU sends the information to the SCADA/EMS in the form of an analog measurement of the available solar resource at that site. The data is collected from all the sensors at the SCADA scan rate of two seconds and then, as with all SCADA analog data, recorded with an accurate (satellite source) time stamp. The SCADA system has been programmed to convert the analog PV measurements into per unit power measurements. The work to this point has been completed.

The next step will be to convert the spot measurement into an approximation of the available PV on the HELCO system, based on the known capacity of nearby DG. Each per unit power measurement will be averaged over a time period (i.e.; thirty seconds or one minute). The averaging will be designed to represent the area smoothing in variability in order to apply the per unit power measurement to a larger area. This averaged per unit power measurement will then be converted to an estimate of the area output by applying the per unit average to the installed PV connected capacity in vicinity of that site. The installed PV connected capacity will have to be manually updated in the SCADA database on a periodic basis and the update will be noted on the display in the future. HELCO has accurate records of how much and where the PV systems are installed. Once the area power is calculated, the areas will be summed into regional subtotals. Tentatively, the regions will be North, South, East and West Regions. Then these four regions will be totaled. This work is expected to be completed by April of 2010.

Below is a capture of the display showing the per unit power level from the installed PV sensors on the HELCO system. This display is available to the System Operator and HELCO corporate users with a nominal 4 second update. The island is represented in a geographic layout and summary information provided for the transmission-side generation production and system frequency. Each sensor is illustrated on this display as a circle, and the color is coded to indicate available power based on the instantaneous sensor reading. The color scale is provided through 10 different colors, from dark blue (low production) to yellow (medium production) to red (highest production). The color legend is shown in the bottom left of the display.

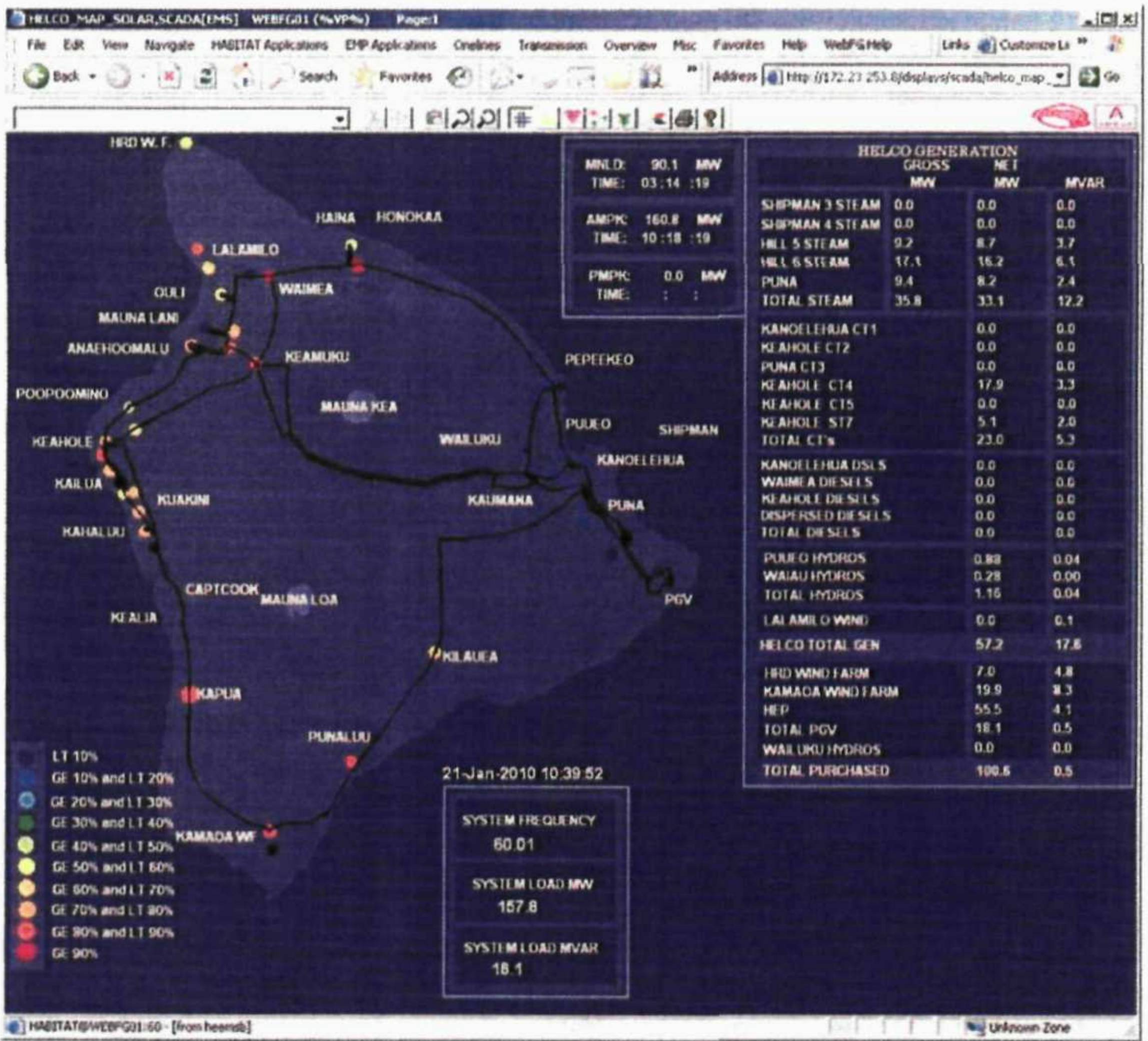


**Figure 2 Display Capture showing Solar PV Energy Readings throughout the HELCO System**

The display capture from January 21 shows that at 10:39 a.m. the east side of the island had low available solar energy (blue circles on the Hilo-side) and high availability in the west and south parts of the island (yellow and red dots).

As discussed above, this display is preliminary and shows just the raw per unit data from the PV sensors. The region subtotals and total for the PV generation will be added below the purchased generation below. The display will probably change with more experience and evaluation of the data.

Additional calculations that will be added to SCADA will be the regional PV energy and the total PV energy. The data will be recorded through existing storage mechanisms and new automatically-generated excel reports. For the present, these numbers will not be added to the official HELCO generation total as they are approximations and not actual generation measurements.

Once HELCO has collected data for a period of time, this SCADA data will be used to do further analysis. HELCO will want to look at the diversity of the power levels on the island in terms of ramp rate, establish typical capacity factors by regions, and develop an understanding of the time of peak production from solar facilities and its correlation and impact on demand. HELCO will also utilize the information about available PV resource to develop resource maps.

**Conclusions and Recommendations**

There is a very high level of distributed generation penetration on the HELCO system, with more projected in the near term. Most of this generation is variable PV. HELCO is among the first utilities in the United States to experience reliability impacts from high DG penetration. Based on the similarity between systems, it is reasonable to expect that MECO and HECO systems will experience similar operational issues for similar DG penetration and the recommendations would be similar.

A limited amount of analysis has been done to understand the reliability impact of the existing level of DG on the HELCO system. The brief underfrequency analysis completed in 2009 confirms that the HELCO system reliability has been negatively affected by the existing level of DG, due to the loss of generation during underfrequency events.

Additional studies are required as soon as possible to evaluate the impact of the existing and projected levels in the following areas:

- System stability through faults and contingencies
- Modifications to system protection including underfrequency and under voltage schemes
- Interconnection requirements for DG including underfrequency and under voltage ride through to ensure system remains operable through faults and contingencies. These would be included into interconnection requirements for DG (Rule 14H).

- Changes to operations necessary to ensure the system remains stable through faults and contingencies (such as modification of reserves)

Field verification is required to ensure that changing undervoltage and underfrequency trip settings results in the desired ride-through during disturbances. Additional discussions with manufacturers and installers should take place to ensure the requirement is interpreted as a ride-through rather than a maximum clearing time (which could mean the inverters may trip sooner). Expanded off-normal frequency and voltage ride-through is a requirement that is not implemented at other utilities and therefore the inverter performance during off-normal frequency and voltage conditions is not proven in actual utility-connected operation.

The cost impacts of the DG need to be better understood, including the contribution to system balancing and frequency control issues, displacement of other renewable energy resources, and contribution to excess energy conditions.

Research a means for monitoring and control of the existing DG is required as the penetration level is equivalent to one of the larger HELCO units and therefore significantly affects real-time operational decisions. A forecast of the variable PV is necessary for unit commitment and may require changes to reserve policies for effective frequency control. The impact of DG during system restoration could be significant as the DG will automatically reconnect in reenergized portions of the grid.

Additional DG connections should be delayed until the analysis above has been completed, and mitigation measures in place to ensure there are not excessive negative impacts on ratepayers or reliability. To facilitate study, more data is required. HELCO has undertaken a project to collect PV data to gain better understanding of capacity factors, variability, and correlation between sites, generation profile, and resource availability in various regions.

Attachment 3

**Evaluation of System Balancing and Frequency Control**

Hawaiian Electric Companies

**Introduction to Balancing and Frequency Control Concepts**

One of the primary measures of a power system's performance is its ability to maintain the balance between supply and demand. The HECO and HELCO grids are autonomous power systems, and there are three independent systems operated by MECO: on Lanai, Molokai, and Maui. The balancing between generation supply and demand is maintained within each of these five island grids independently.

Each interconnected power system operates as a machine, with all responsive generators within the island working together to supply the electricity demand on the system. All AC power systems perform balancing, but the difference between the HECO companies' systems and the mainland power systems are the size of the interconnections and the isolation from other systems. The small size of the island power system (island interconnection) results in a much greater sensitivity to imbalance, and a greater degree of volatility, in comparison with the interconnections on North America (the Texas, Western, Eastern, and Quebec interconnections).

The measure of system balancing is the system frequency which is measured in cycles per second or Hertz (Hz). If the total demand on the power system exceeds generation supply, the frequency decreases below the target frequency, which is typically 60 Hz. Conversely, if the total generation supply exceeds the total demand on the power system, the frequency will rise above the target.

The measure of the system sensitivity to imbalance is the Frequency Bias. The Frequency Bias measures the imbalance, in MW, to cause a change in frequency of 1/10 Hertz. The frequency bias is dependent upon the characteristics of the interconnected generators and loads on the power system, and therefore varies throughout the day depending on the generators and loads connected to the system. Below is a comparison of typical frequency bias values for three larger HECO company systems (HECO (Oahu), HELCO (Big Island), and MECO (Maui) in comparison with the smallest North American interconnection (ERCOT, in Texas).

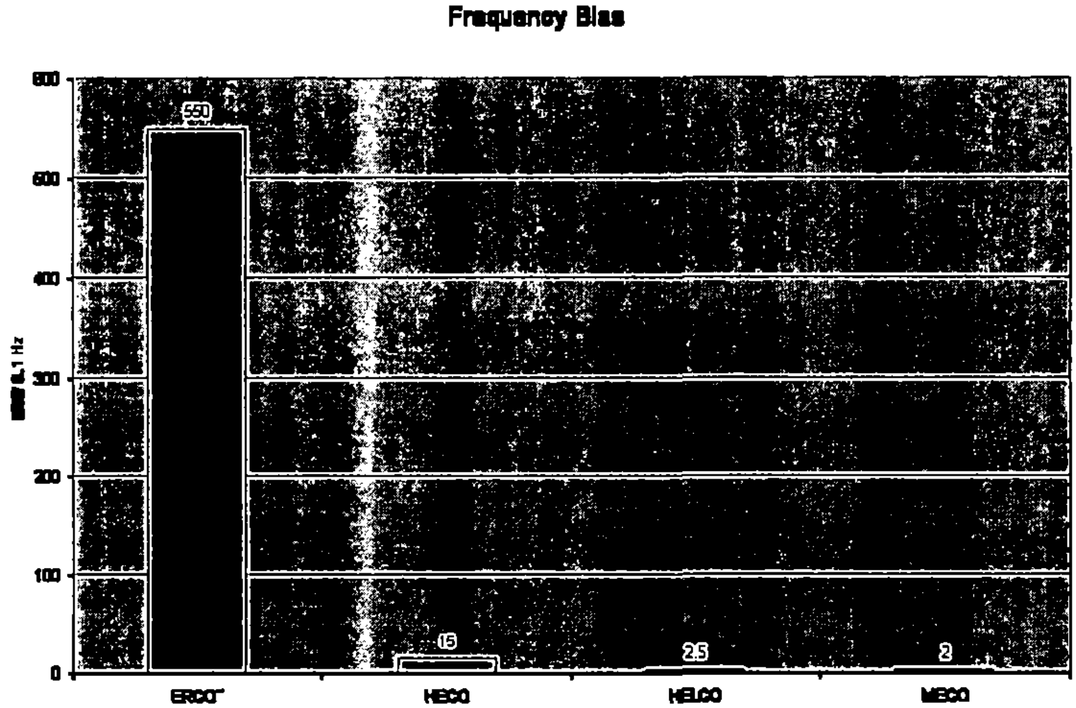



**Figure 1 Frequency Bias of the smallest interconnection in North America, in comparison with HECO, HELCO, and MECO typical bias.**

The North American Electric Reliability Corporation (NERC) has created a good tutorial on power system balancing and frequency control is at it can be found http://www.nerc.com/docs/oc/rs/NERC_Balancing_and_Frequency_Control_Part_1_9Nov2009_(Revision2).pdf
The importance of the system frequency as a reliability measure is emphasized in a quote from this reference: *"Frequency can therefore be thought of as the pulse of the grid and a fundamental indicator of the health of the power system".*

As mentioned above, HECO companies differ from the interconnections in North America in that there are no interties to other power systems. NERC, the entity responsible for monitoring balancing and control in North America, has defined performance criteria to measure system balancing as a key reliability measure. For the interconnected utilities, the system balancing is done with consideration for the frequency of the system, but also to maintain the target import or export of power across the tie lines. For the HECO companies, all imbalance results in frequency error, and there is no interchange to monitor. The result is that imbalance is a problem on a more immediate time frame; on the mainland the generators work together within the interconnection and an imbalance within a portion of the interconnection will result unscheduled import or export from the neighbors which provides a time buffer to address the imbalance. When there is imbalance between demand and power generation, the HECO companies' systems will experience frequency error rather than interchange error.

## Attachment 3

**HELCO System Frequency Targets and Action Levels**

| | |
|---|---|
| 59.95 – 60.05 Hz | Targeted Frequency Control Range |
| 59.85 - 60.15 Hz | Disturbance level: System Operator to identify cause and take corrective action |
| 59.80 – 60.20 Hz | System Alarm Level: Operator to take immediate corrective action |
| 59.5 Hz | Emergency Action Level: Mandatory manual load shed by the System Operator required if not corrected within 15 minutes |
| 59.3 Hz | Block 5 Automatic load shed if frequency remains at this level for approximately 20 seconds |
| 58.8 Hz | Block 1 instantaneous automatic load shed |
| 58.5 Hz | Block 2 instantaneous automatic load shed |
| 58.0 Hz | Block 3 instantaneous automatic load shed |
| 57.7 Hz | Block 4 instantaneous automatic load shed |

**Balancing and Frequency Control Time Scales**

Balancing and frequency control is performed by different resources over various times scales:

1. Primary control – seconds
2. Secondary control or supplemental control – several seconds to minutes
3. Tertiary control - minutes to hours

Only online (spinning) resources can contribute to primary and secondary control. Certain offline (non-spinning) resources can contribute to tertiary control.

**Primary Control (Frequency Response)**

Primary control is commonly described as Frequency Response. Frequency Response occurs automatically due to the characteristics of equipment connected on the system. The Frequency Response is the immediate response of the system to a change in frequency, and it is required to stabilize the system. It is critical that the online resources provide sufficient frequency stability to ensure survival of the interconnection through faults and contingencies until the secondary time period. If the primary control response is insufficient to stabilize the power system, the system can fail before the secondary and tertiary control measures can occur. This stability can only be analyzed through special dynamic simulations. The challenge of these simulations can be accurately modeling the frequency response of the generating equipment and load on the system.

Frequency response is provided by governor droop action and load.

Attachment 3

1. **Governor droop action**: The governors on the conventional units (diesels, gas turbines, and steam units) on the HELCO system sense a change in the frequency and adjust their energy output into the generator's prime mover to counter (slow) the change in frequency. The nominal droop setting for units on the HELCO system is 4%. However, over time the wear and tear on mechanical governors of the steam units resulted in reduced droop characteristics. HELCO is replacing the mechanical governors with electronic governors for the three must-run steam units (Hill 5, Hill6, and Puna). This has been completed for the Puna steam unit and is planned for the two Hill units. The solar, wind and hydroelectric renewable energy resources on the HELCO system do not provide a droop response. The geothermal resource also does not provide a droop response; however, HELCO is working with the geothermal provider to add droop response on some of their existing, as well as anticipated additional, generating units. During periods of high renewable energy production, relatively few generators on the HELCO system provide frequency response. A study performed on the HELCO system identified that the HELCO steam units are critical to providing frequency stability. As a result, HELCO has established an operating policy of no fewer than two steam units online at any time to ensure the system can survive single generator contingencies without becoming unstable (resulting in failure).. Extreme changes in frequency can cause combustion control and boiler control problems, which may also result in trips. Extended operation at low frequency will create equipment stress on the responsive units as the governor response will drive output outside of the equipment's normal operating parameters and can cause trips. Loss of any generation during low-frequency creates a high risk of cascading failures as the generation loss exacerbates the existing imbalance and places more stress on the remaining responsive generators. For this reason, it is important that generation remain connected during low-frequency events as much as possible, and be coordinated with the underfrequency load-shed scheme.

2. **Load**: The motor loads on the HELCO system contribute to system frequency response through their speed changes in response to frequency. As frequency drops, motors draw less energy. Load is also utilized to balance system frequency in the primary control time frame through the use of instantaneous underfrequency load-shed. The underfrequency load-shed scheme reduces demand by opening a number of distribution circuits when frequency declines to a specified level to ensure the system will not fail in the primary control time frame. The underfrequency scheme is designed to shed enough load to restore system frequency to a stable level so that generation can be increased, and standby generation can be brought online in the secondary and tertiary time frames. It is important to shed the correct amount of load: too much load shed will result in over-frequency, too little will result in the system remaining at depressed frequency. The first tier of instantaneous underfrequency load-shed occurs at 58.8 Hz and the lowest tier is shed at 57 Hz.

Attachment 3

A typical cause of frequency disturbance is loss of a generating unit. Below is plot illustrating a typical frequency excursion resulting from loss of a generating unit on the HELCO system in the primary control time frame.

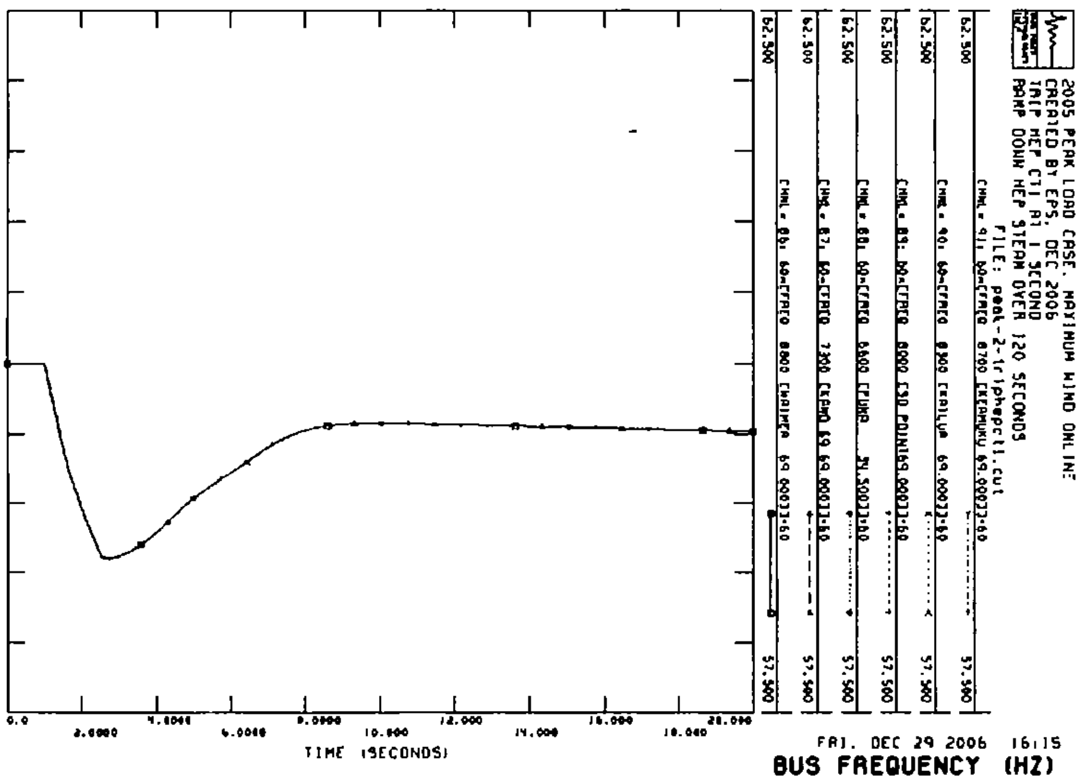



**Figure 2 Result of modeling frequency response to a loss of generator event on the HELCO system. The frequency is shown on the "y" axis and time on the "x" axis.**

The lowest excursion of frequency is described as the "frequency nadir". The frequency response results in the frequency rebounding and stabilizing from this low point. Note that the primary control response results in a stable frequency, but does not restore frequency to the pre-disturbance value.

**Impact of Renewable Energy Resources on Primary Frequency Control**

Any change in the typical generation mix on the HELCO power system should be analyzed to understand the impact on the dynamic response of the system.

Renewable generation with variable output (primarily wind and PV) creates imbalance by virtue of the unscheduled, uncontrolled changes in output. These changes occur too quickly to be addressed in secondary and tertiary time periods, and result in a greater number of load changes in the responsive generators than would occur due to demand. The average frequency error on the HELCO system has increased with the addition of two wind plants. Under some wind conditions, wind plant variability has caused combustion control problems at the steam units due to the load changes from the governor droop response. Under such conditions the system operator can send a curtailment signal to the wind plant. The wind plant operator uses the wind plant controls to reduce export to no more than the curtailed level which results in a more stable output, and therefore, more stable frequency.

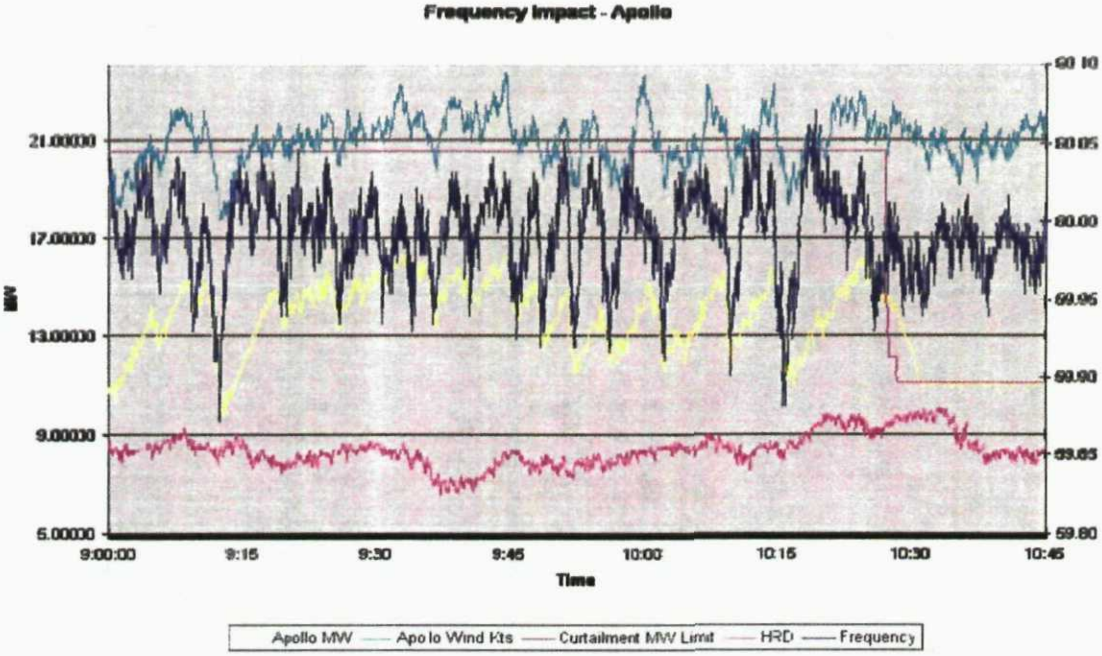



**Figure 3 Wind plant affecting frequency in the primary control time scale. System frequency stabilizes when the wind plant uses plant controls to reduce and stabilize output.**

Renewable generation (or any generation) has a possible impact on the HELCO primary frequency control in two ways. First, the addition of the renewable generator may change the frequency response of the power system by displacing responsive generation which would otherwise be online, or by forcing responsive generation to operate closer to its limits (changing the available range of operation on responsive units). Secondly, renewable generation can affect the frequency response if the equipment does not remain connected through depressed frequencies.

If the renewable energy generator provides fault ride-through capabilities and frequency response to the power system, similar to the conventional units, then the impact on frequency control may be neutral or even positive. Generation which has this potential includes geothermal and biomass facilities, providing they are designed with these objectives in mind. The anticipated geothermal and biomass additions on the HELCO system are required to provide inertial response, underfrequency ride-through, and governor droop response to maintain or improve the HELCO system frequency response.

The PV, wind and hydroelectric plants on the HELCO system do not provide a governor droop response. The existing geothermal plant also does not provide a governor droop response. At times of high energy production from these non-responsive resources, there is a reduction in the frequency response on the HELCO system. During higher demand periods, the frequency response is reduced on the system because conventional units that would have been operated to meet demand are displaced by the production from the wind and hydroelectric resources. This reduces the consumption of fossil fuels, but also reduces the number of generators on the system that would have a frequency response. During lower demand periods, the must-run conventional units are operated near minimum load to accommodate the wind, hydro, and geothermal production, and these resources may have to be curtailed. Operating the responsive units near their minimum load reduces the available response range for loss-of-load events. Such events (which result in high frequency) could drive the responsive generators below the point of operability and cause them to trip offline. This issue is discussed further in the section on curtailment analysis.

The wind, hydroelectric, and geothermal plants remain online through off-normal frequencies. However, distributed generation connected with typical underfrequency trip settings according to IEEE 1547 guidelines trips will trip at 59.3 Hz. A consultant study for the HELCO system analyzed the impacts of various levels amounts of PV set to trip at 59.3 Hz for a variety of base case scenarios. In all scenarios, even a relatively small amount of PV (2 to 2.5 MW) caused the system to enter another tier of load-shed or a lower frequency nadir. The analysis highlighted the fact that the minimum system frequency that occurs during a disturbance appears during the transient time frame, before the primary frequency response from generators can fully respond along their droop line.

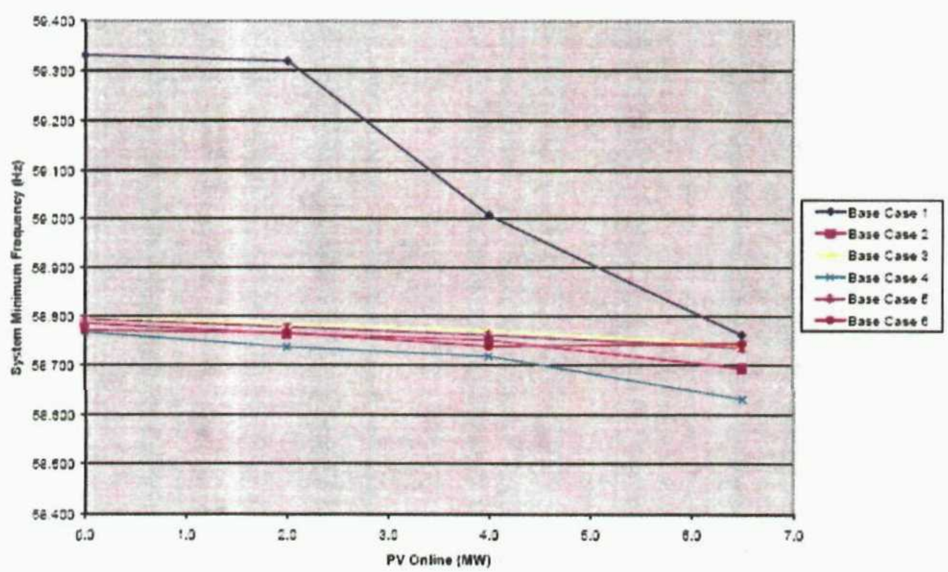



**Figure 4 Plot of frequency nadir reached for loss of Hill 5, for various levels of PV set to trip at 59.3 Hz on the HELCO system under six base case scenarios.**

As a result of this investigation, HELCO requested existing PV installations alter the frequency trip settings (where possible) and for new installations to change the trip setting to 57.0 Hertz to minimize the impact of the aggregate loss of PV on the

HELCO system during frequency excursions. Not all existing PV was able to comply. At this time, just less than 4.4 MW of distributed PV capacity on the HELCO system will trip at 59.3 Hz, and this will increase to just over 4.5 MW with the projects in progress within the year. The study illustrated that this amount of PV has already had an impact on HELCO's system frequency response and will result in additional customer load shed during certain contingencies if that block of PV is producing 2 to 2.5 MW. This is discussed further in the analysis of distributed generation impacts.

**Secondary and Tertiary Control**

Secondary control includes the effect of control actions by Automatic Generation Control. It is considered the regulation time frame. HELCO AGC performs on a four-second cycle. During typical conditions, AGC allocates demand to those units under its control to minimize costs (economic dispatch) and to make adjustments on a somewhat faster time scale to correct frequency for changes in demand (regulate frequency and load-following). In order to accommodate typical intra-hour balancing, HELCO maintains online regulating reserves to handle anticipated changes in demand within the hour. Regulating reserves are provided by the spare capacity (up and down) on those online units that are immediately responsive to AGC control.

The units that are capable of participating in AGC regulation and control are those same units providing primary frequency control: the diesel, gas turbine, and steam units. In order to ensure that there is sufficient capability to manage system frequency in the secondary and tertiary time frames following most contingencies; HELCO operates no fewer than three generating units under AGC control. The two combined cycle facilities (Hamakua Energy Partners and Keahole Combined Cycle) are each dispatched as a single entity and thus for the purposes of this requirement, each is considered a single unit under AGC control although they may be comprised of up to three individual units when operating in dual train mode.

The role of AGC during a frequency disturbance, such as a unit trip, is to restore system frequency to 60 Hz (or the target value). As illustrated in figure 2, the primary frequency control stabilizes system frequency but does not return the frequency to pre-disturbance frequency. That is the role of AGC.

During a trip event, the system frequency suddenly drops and conventional units under AGC control will increase output (without signal from AGC) through the droop response. In the first seconds of a disturbance AGC suspends control to allow the generators and system to stabilize through primary control actions. Once the generators have stabilized, AGC control automatically resumes control. AGC issues controls to increase output on those units under AGC control that have unused capacity until system frequency is at target. If the regulating units have insufficient reserve to compensate for the generation lost in the contingency, the system frequency cannot return to 60 Hz until the system operator brings online standby generation resources. AGC will raise units to the capacity limit under such a case but frequency will remain below target. If the droop response carries a unit beyond its maximum limit, AGC will not lower the unit back down to its dispatch limit if frequency is outside of the regulation region as it would worsen system frequency. If the condition risks the generating unit, the local operator of the generator must take actions to lower the unit output at the plant.

The HELCO system has fourteen small diesel units which can be brought online within 2.5 minutes or less. When a large loss of generation occurs, the system operator can start all of these resources with a single control action. As each unit comes online, it can be placed on AGC control and AGC will issue controls to balance system frequency.

If a disturbance requires actions beyond ten minutes, it is considered tertiary control. Tertiary control could include bringing on additional units for reserve requirements, or changing from the emergency generation mix used to stabilize the system with a more economic dispatch. For example, taking off the diesel units and bringing online a second train in combined cycle which may require an hour to come online and be dispatchable. The operator determines in this longer time frame, which units will be brought online to meet the anticipated demand on the system during periods of load rise (morning through sunset), and which units will be brought offline as demand decreases to the minimum use period (evening through early morning).

The system balancing does require a certain amount of regulating capacity. At present, the regulating requirements are managed by the operational requirement for at least three generating units under AGC control participating in frequency regulation, and the minimum regulating reserves requirement (9 MW down, and 6 MW up). Reserve requirements are modified by the System Operator based upon the observed wind plant production and variability (this is discussed in more detail below in the section on impacts from renewable generation) or other special operating conditions. The system operator adds additional dispatchable generating resources on the system when up-reserve approaches the minimum (during periods of load increase). The system operator removes dispatchable resources from the system when down-reserve approaches the minimum (during periods of load decline). When no additional dispatchable resources can be removed from the system, the system operator curtails output from non-dispatchable resources. This is discussed further in the section on curtailment and excess energy.

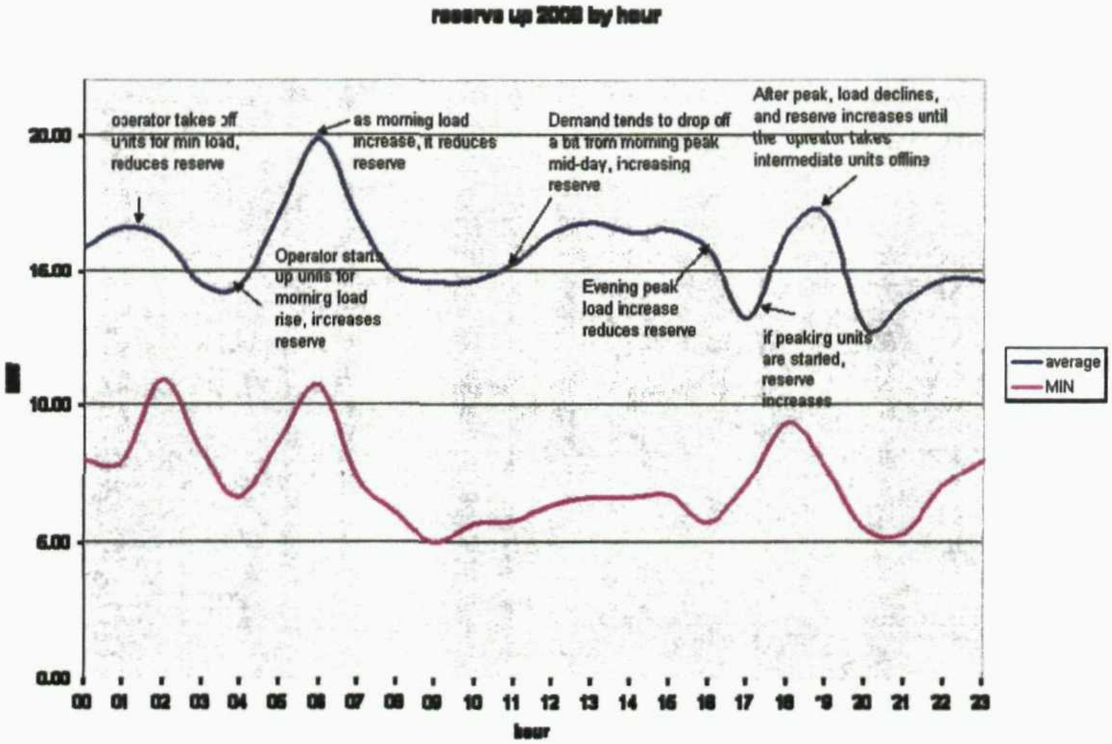



**Figure 5 5 Average and minimum up regulation reserve on the HELCO system on hour of day, showing triggers for reserve increases/decreases. Amount of reserve is dependent largely on size of the next dispatchable generator in the commitment stack.**

## Impact of Renewable Energy Resources on Secondary and Tertiary Control

### General Discussion

If a renewable energy resource is dispatchable under AGC, it can participate in secondary control and tertiary frequency control. The impact could be positive or negative, and would depend on whether it displaces other dispatchable resources, and how well its control and response capability compares with displaced resources. The future biomass and geothermal expansion projects are expected to be dispatchable under AGC control. The ramp rates and dispatch range will be less than available from the existing combined cycle and simple cycle gas turbines, but will be comparable to some of the older steam units.

The existing geothermal, hydroelectric, wind and PV generation are not dispatchable through Automatic Generation Control. The geothermal, hydroelectric, and wind facilities are telemetered by SCADA/EMS – and therefore their output is monitored by AGC – but the distributed PV is not visible to the system operator or AGC with one small exception.

The geothermal and hydroelectric facilities have relatively stable output and therefore although not dispatchable, do not add to the regulation requirement on the system other than through displacement of other generation that could be dispatched. However, the wind resources are extremely variable and required significant changes to the control algorithm for AGC, as well as operational changes to reserve policies.

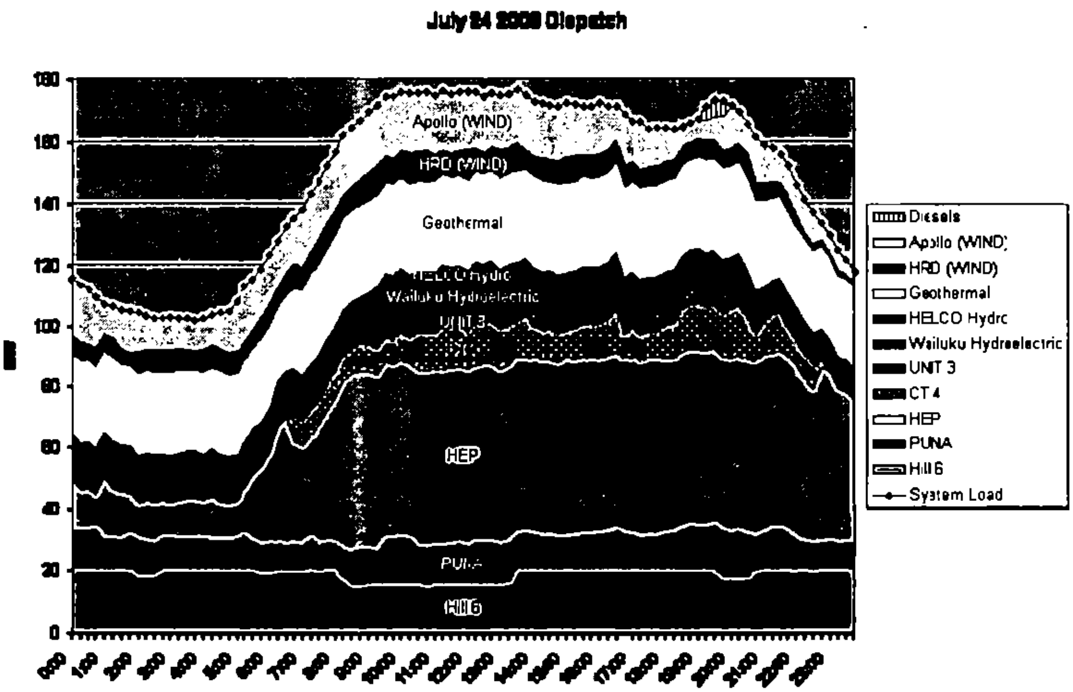



**Figure 6 Stack chart showing dispatch on July 24, 2008. Only the units in grey participate in primary and secondary frequency control.**

The figure above shows a load curve and the addition of resources throughout the day to meet the demand. The conventional units provide all the primary and secondary frequency response. During minimum load periods, only three units remained online to provide all frequency response and control (HEP, Puna, and Hill 6). The remaining energy (majority of power) was provided by non-responsive renewable energy resources.

### Wind Impacts

The impact of the two wind plants (Hawi Renewable Development, or HRD; and Tawhiri, also referred to by HELCO as "Apollo" or "Kamaoa" due to past names) on HELCO's frequency management and AGC control is documented within two EPRI reports. The first report studied AGC changes and impacts from the HRD facility (10.5 MW) and the second studied the additional impacts following the connection of Tawhiri (20.5 MW).

Project #1

EPRI Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation. EPRI, Palo Alto, CA: 2007. 1018715.

Project #2
Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance – Phase 2. EPRI, Palo Alto, CA: 2009. 1018716.

The results of Phase 1 (impact of HRD project alone) showed that the most effective measure for improving HELCO's frequency control with the wind plant came from retuning of the AGC unit and area control parameters. Various other steps taken and their effectiveness are documented. Following the AGC improvements, and based on several hours of comparative monitoring, the frequency performance of the system was 10-30% lower. There was a significant increase in magnitude and number of AGC control actions.

The Phase 2 analysis was conducted following the addition of the 20.5 MW wind plant. 4-second data was collected over 35 days in the summer of 2007. Statistical analysis was performed on this data. In addition, event analysis was performed for specific frequency events. The statistical analysis confirmed that wind fluctuations are the predominant driver of frequency error on the HELCO system, particularly when wind plants are at the mid-range of the power curve. The biggest impact on regulating units occurs when there are periods of wind ramping/variability occurring in conjunction with periods of load ramping. The statistical analysis is summarized in the table below, showing the frequency variation, number of controls, and magnitude of controls (travel) during low/high wind ramp periods and low/high load ramp periods.

| | | Low Load Ramping | | | High Load Ramping | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Freq. band | Num Ctrl | Travel | Freq.band | Num Ctrl | Travel | Freq.band | Num Ctrl | Travel |
| Low Wind Ramping | Mean | 0.10 | 198.50 | 17.10 | 0.12 | 216.12 | 26.04 | 0.11 | 226.83 | 21.49 |
| | SD | 0.03 | 134.75 | 11.12 | 0.03 | 100.87 | 11.70 | 0.04 | 155.35 | 14.80 |
| | Min | 0.05 | 55.00 | 3.34 | 0.06 | 91.00 | 10.05 | 0.04 | 30.00 | 0.85 |
| | Max | 0.21 | 710.00 | 68.07 | 0.25 | 596.00 | 74.78 | 0.31 | 942.00 | 116.40 |
| | | | | | | | | | | |
| High Wind Ramping | Mean | 0.16 | 358.94 | 36.80 | 0.18 | 315.88 | 40.66 | 0.16 | 351.38 | 38.77 |
| | SD | 0.07 | 217.91 | 16.42 | 0.14 | 137.58 | 21.56 | 0.09 | 187.37 | 18.14 |
| | Min | 0.06 | 86.00 | 10.28 | 0.08 | 130.00 | 22.73 | 0.06 | 83.00 | 9.84 |
| | Max | 0.46 | 954.00 | 90.60 | 1.09 | 854.00 | 158.31 | 1.09 | 954.00 | 158.31 |
| | | | | | | | | | | |
| Mean – %Inc | | 59.6 | 80.8 | 115.2 | 50.5 | 46.2 | 56.1 | 45.9 | 54.9 | 80.4 |
| SD – % Inc | | 101.3 | 61.7 | 47.7 | 316.9 | 36.4 | 84.2 | 139.7 | 20.6 | 22.6 |

**Figure 7 Table summarizing of frequency band and control actions and MW travel on regulating units under low/high wind ramp conditions and low/high load ramp conditions. Information extracted from the report *Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance – Phase 2. EPRI, Palo Alto, CA: 2009. 1018716***

The frequency band, control actions on the regulating units, and amount of MW travel for the regulating units all increased during high wind ramping versus low wind ramping periods. As shown in the final two rows of the chart in Figure 7, the mean increased 45-80% and standard deviation increased 20% for controls and 140% for frequency band.

Attachment 3

The analysis also showed that wind ramping led to large frequency deviations.

A significant finding with the addition of the second wind plant was that the high-frequency (second to second) variability of the wind is the most difficult to mitigate. In order to avoid over-compensation through the AGC actions in response to frequency error created by the rapid and bi-directional wind variations, the "no control" dead band within AGC had to be increased. This dead band is managed through the definition of the ACE control region, in terms of MW, and therefore its correlation to frequency is dependent upon the frequency bias. During periods of lower frequency bias, the no-control deadband is +/- 0.2 Hertz. The implications of this are that the frequency is allowed to deviate well outside the desired operating range of +/- 0.05 Hz before AGC takes corrective action. Frequency error within the +/- 0.2 Hz range is managed by governor droop response unless the error accumulates into the control range. Another step that had to be taken to improve the frequency control of the system was to force allocation of regulating reserves across all must-run units.

The system operator monitors the wind output in real-time. Under periods of steady high wind output or minimal wind output, minimal up-reserves are required. However, the largest frequency deviations caused by wind plants (other than from facility trips) have resulted from sudden down-ramps in wind. Up-ramps can be mitigated by curtailments, but down-ramps will result in large drops in frequency unless there is sufficient online reserve capacity, and sufficient ramping capability, to compensate for the sudden decline. The system operators have utilized the diesel units in such cases to avoid underfrequency loadshed.

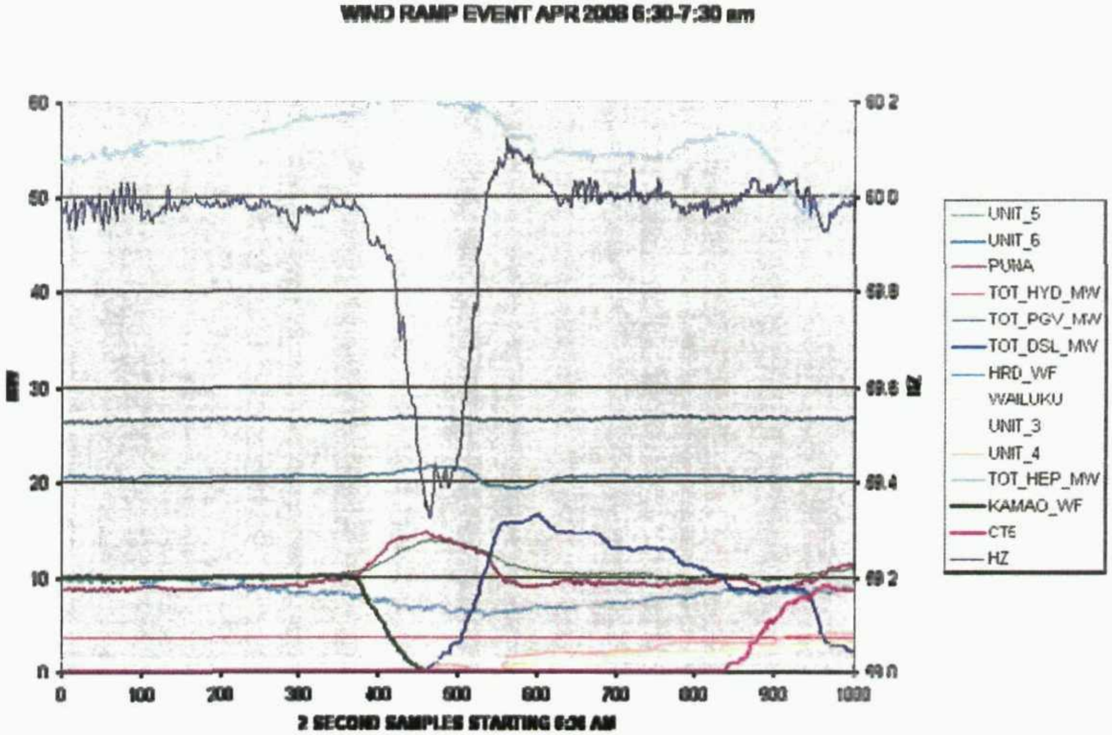



**Figure 6 Wind ramp event. The system operator started diesels to restore system frequency.**

HELCO is working with NREL and a wind forecasting entity on a preliminary assessment as to whether or not custom forecasting utilizing targeted field measurements can be utilized to anticipate periods of risk for wind ramps. HELCO operations could then retain reserves on the system, or curtail wind plants, in advance of the ramp as appropriate to avoid a system frequency disturbance.

## Impact of Distributed PV

The impact of the distributed PV is difficult to quantify at this time as these resources are not monitored in real-time. The system operators observed that the day peaks are more variable from day to day, but how much of this is due to change in customer use and how much is the influence from the distributed PV output cannot be determined without actual measurements. The load-duration curves do show the most pronounced decline in demand between 2009 and 2008 was in the mid-day load range, during which PV would be available. This is covered in more detail in the discussion of curtailment and excess energy. The concern about PV is whether the variability will contribute to the existing challenges with frequency control, and the need to forecast the PV contribution in order to determine the amount of reserves that may be required. A project is being undertaken to provide an estimate of PV production in real-time tracking and data collection of this number. This is described further in the discussion on distributed generation resources.

## Reserve Policies

In the past (before the addition of the large wind plants), regulating reserves were allocated by economic dispatch, but this did not provide enough response capability under variable wind conditions. Since then, the amount of reserves has increased, in part due to operating at part-load to accommodate renewable resources, and in part due to the need for regulating units to remain online due to uncertainties in the forecast and the variability of wind and PV resources. Whether regulating reserve policies need to change for the anticipated change in the generation mix on the HELCO in the next two has not been analyzed.

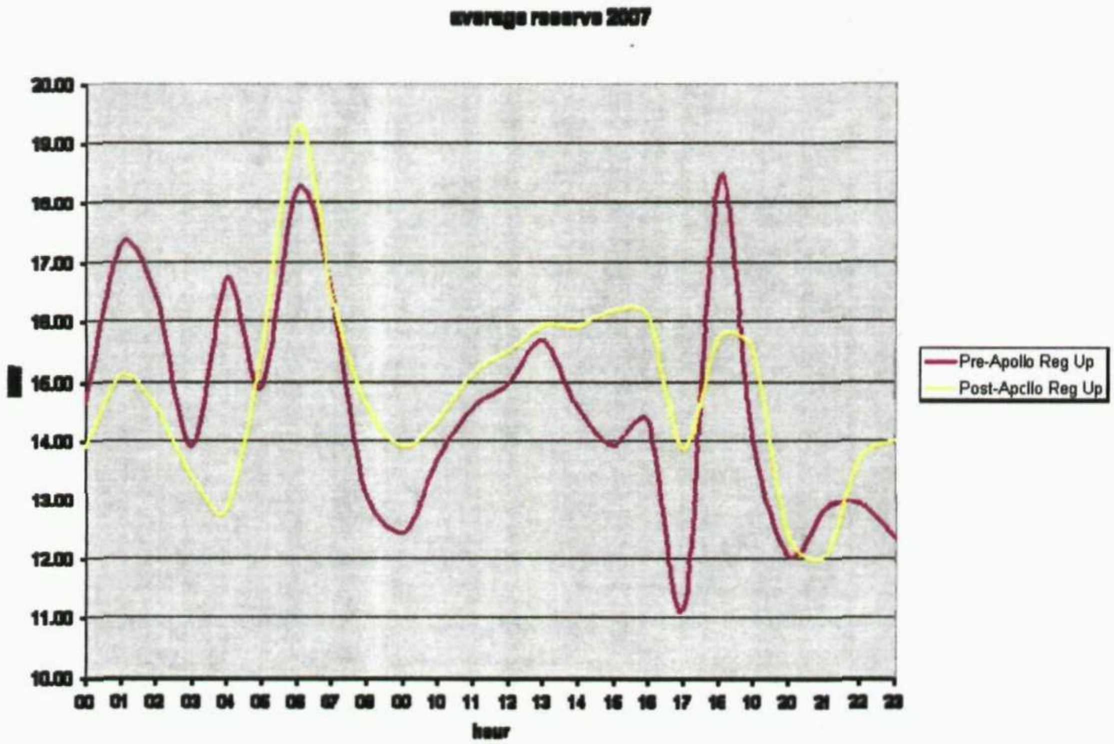



**Figure 7 Hourly average reserve up values before and after the addition of a 20.5 MW wind plant on the HELCO system.**

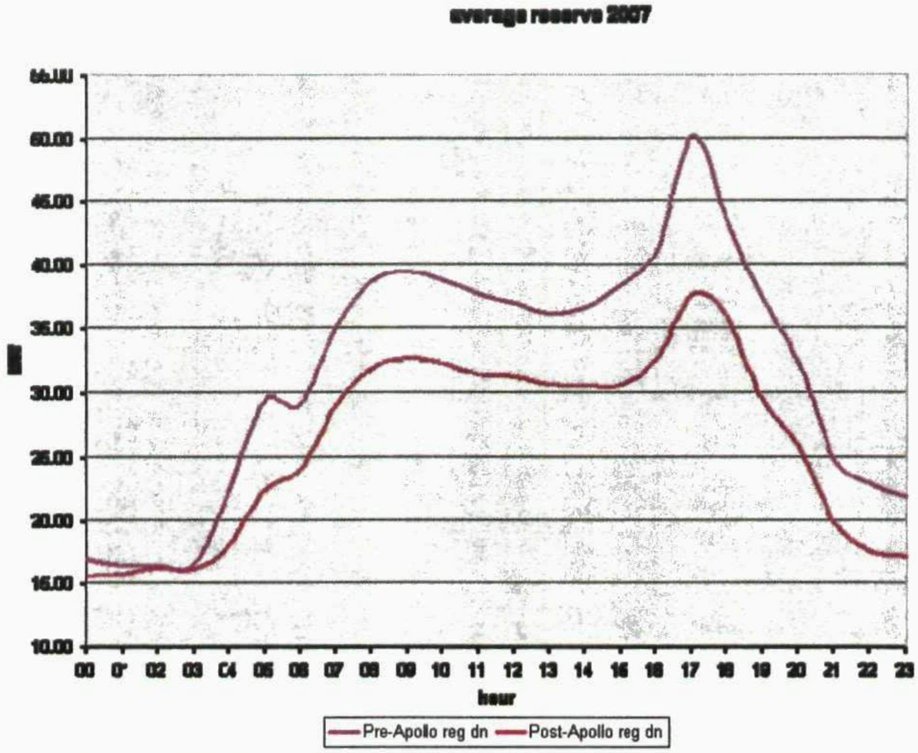



**Figure 8 Hourly average reserve down values before and after the addition of a 20.5 MW wind plant on the HELCO system.**

## Conclusion

- System frequency control and balancing is challenging on the HELCO system due to being a small isolated system and a large number of must-take energy from generating facilities which do not participate in frequency response.
- The variable output from wind generation on the HELCO system had a profound and measurable effect on frequency control. HELCO has taken many actions to mitigate the impacts of the variable wind on frequency control, including modification of the AGC program and parameters, changes to reserve policies, and changes to governor droop settings and equipment. Even with these actions, variable wind is the largest driver for frequency error on the HELCO system.
- The cost impacts associated with the change in reserve policy, use of emergency diesel units, and increase in number and magnitude of controls on regulating units have not been quantified and are difficult to capture or analyze with available tools.
- The existing and potential impacts of distributed PV on the daily load demand and existing frequency control cannot currently be quantified or studied as it is not presently monitored and there is no available data regarding expected capacity factors and variability. However, with nearly 6.8 MW of variable distributed generation on the system today and 14.7 expected by the end of 2010, this likely comprises a significant percentage of daytime generation on the HELCO system.

- Aggregate loss of this distributed generation during faults or generator contingencies is a concern. Trips during low-frequency result in a lower frequency nadir or additional loss of customers; trips during voltage updates may trigger underfrequency load shed where none would otherwise have occurred.
- The impact and uncertainty associated with the generation from wind, hydro and PV resources has increased the difficulty in load forecasting in the operational and planning time frames. This makes it difficult to optimize the generation commitment order and maintenance schedules.
- As participating units are displaced, the system frequency response is reduced. With large amounts of must-take energy forcing units towards minimum, the system is at risk of over-frequency events which can lead to cascading outages.

**Recommendations**

- The HELCO system has maximized variable generation. Additional variable generation will add to excess energy and frequency control and balancing problems and such additions therefore should be minimized. Of particular concern is variable generation that will increase the second to second frequency error beyond that already caused by variable wind generation, which would require increasing the "no control" deadband for secondary frequency control by AGC.
- The existing units providing primary and secondary frequency control and regulation cannot be displaced except by units providing the same or better frequency control and regulation characteristics. Generation additions of any significant amount (in aggregate or individually) need to participate in primary frequency control.
- Changes in generation dispatch mix need to be analyzed to ensure that the system remains stable through faults and contingencies in the primary control time frame and to define operational reserve policies to ensure sufficient response capabilities in the secondary and tertiary control periods.
- Data regarding the existing and anticipated PV characteristics is required in order to study the operational impacts on frequency control and balancing. A pilot project based on collecting data and numerous substation locations is in progress. This data can be used to modify load forecast and develop an understanding of impacts on reserve requirements.
- The droop response for all conventional units should be improved if not presently able to achieve 4%. Work has been completed for one governor replacement and projects are underway for two more steam units.
- Continue research into possible ramp forecasting techniques.

Attachment 4

**Evaluation of Excess Energy and Curtailment**

**Hawaiian Electric Companies**

Must run units are units that must remain online (cannot be cycled offline and online) during the day. There are two reasons units are considered must-run:

1. Operationally Critical Generation: In order to maintain system reliability, a minimum number of conventional units must remain online. Units in this category may be critical because they provide critical grid services such as: system stability and reliability through faults and contingencies, voltage regulation, frequency regulation and load following. These units are required to operate in order to meet the following objectives:
    a. System remains stable and within operating limits through faults and contingencies (to ensure ability to serve)
    b. Ensure sufficient responsive generation, to provide frequency control and balancing (considering both primary frequency control and supplemental frequency control time frames)
    c. Sufficient capacity is available to meet demand for changes in variable generation and loss of the largest unit (how much of this reserve can be in the form of fast-starting offline generation varies by company).

2. Generator Characteristics: Some technologies (such as geothermal and biomass) have limited ability to cycle off and online, and must remain online except during maintenance and outage periods. There may also be limitations on cycling capability imposed by permits, or due to lengthy minimum down times, which preclude taking a unit offline. Some units in this category may also provide critical grid services.

**Must-take Units**

Must take units are those units whose output is accepted onto the system regardless of cost, as long as the system can accommodate the units. The must-take units include:

1. Output from distributed or small generation facilities which are not monitored or controlled by the system operator (i.e.; does not have a SCADA interface). This generation appears to the system operator to be a demand reduction. Distributed generation may be load-offsetting (no-sale) and export (schedule Q, NEM, FIT). Most of this generation is solar-PV.
2. Solar PV and Concentrated Solar generation monitored or controlled by the system operator.
3. Output from the run-of-river hydroelectric facilities monitored or controlled by the system operator.
4. Output from the wind facilities monitored or controlled by the system operator.

5. Contractually obligated energy purchases, where a minimum take or minimum dispatch level is specified by the contract.

Much of the generation in this category does not contribute to critical grid services. The variable generation sources (PV, wind, hydro) contribute to frequency control and balancing requirement from the units providing those services.

**Excess Energy**

Excess Energy is a condition which exists when the amount of generation being produced on the system exceeds the availability of the system to take the generation. Excess energy exists when the must-run units are at their minimum dispatch level, with consideration for down-reserves to respond to typical load loss events and yet the system frequency is high (above 60 Hertz). This indicates that the production exceeds the demand on the system. When production exceeds demand, the system frequency will rise. At this point it is necessary to reduce the production from must-take generation resources in order to balance system production and demand. This condition occurs routinely on the MECO and HELCO systems today, primarily during the off-peak times of day. An example of a 24-hour period with curtailments is provided below.

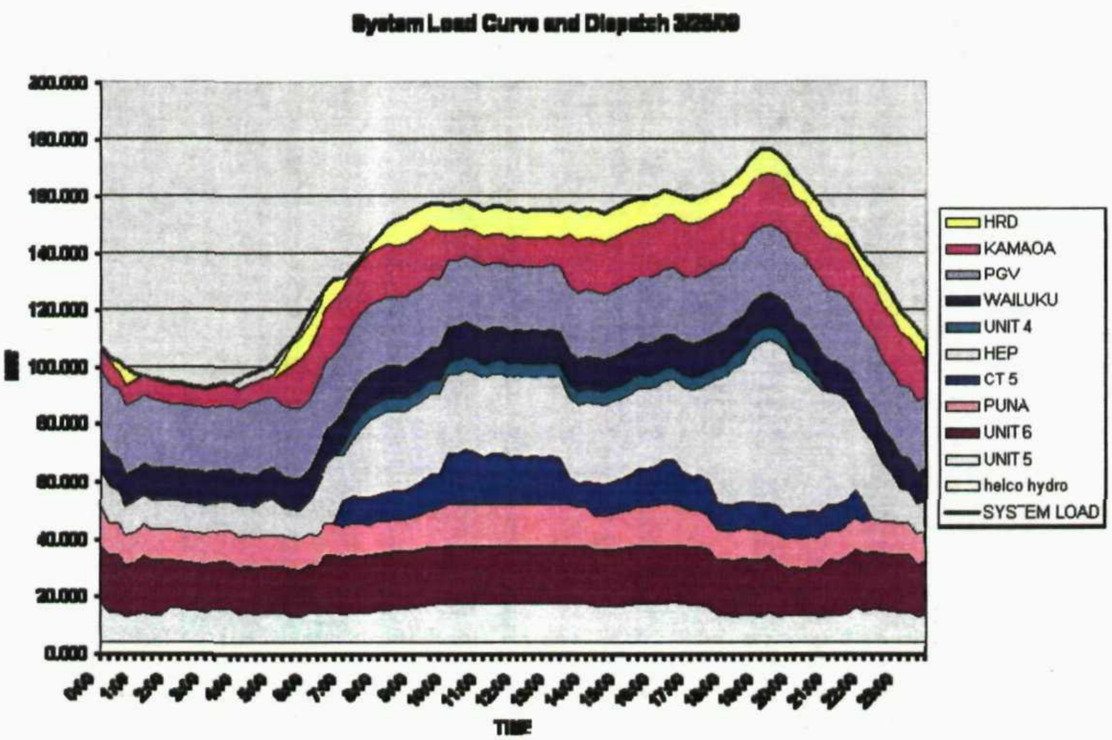



**Figure 1 HELCO generation dispatch on 3/25/09. Curtailment of HRD and Kamaoa was necessary during lower-demand periods.**

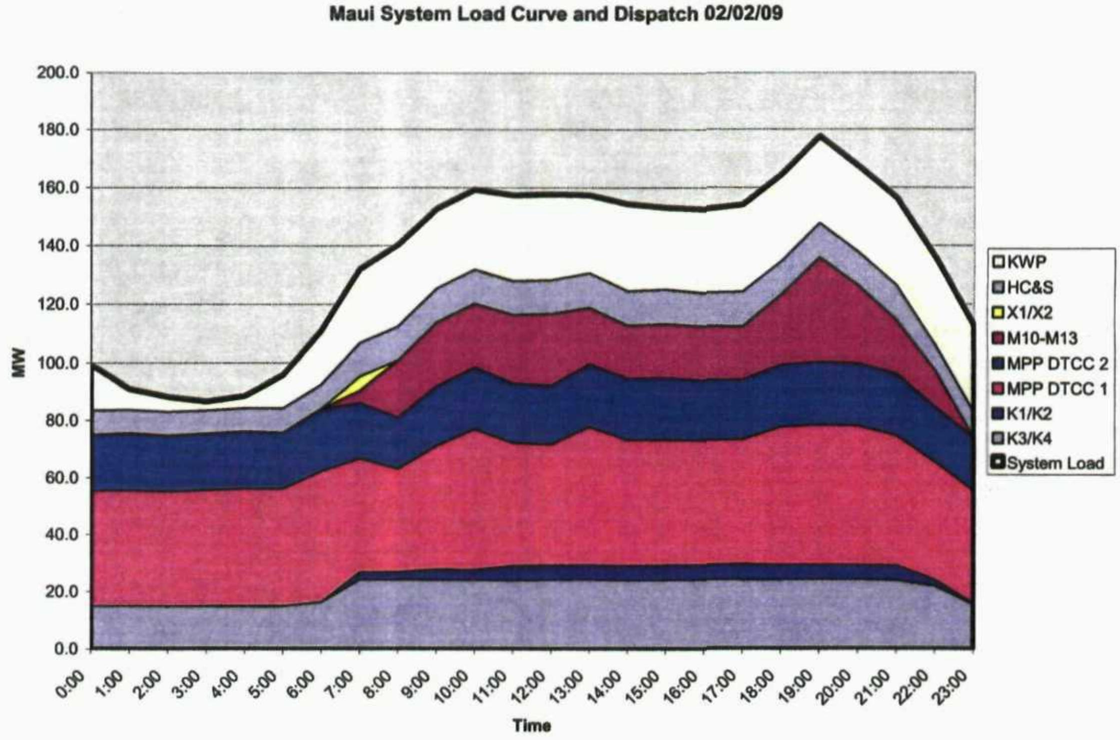



**Figure 2 Maui generation dispatch on 02/02/09. Curtailment of KWP was necessary during lower-demand periods.**

The amount of hours of curtailment will depend on the customer demand, the production from the must-take energy sources, and the mix of must-run units. The figure below illustrates a range of possible hours of curtailment for the present HELCO generation mix.

Attachment 4

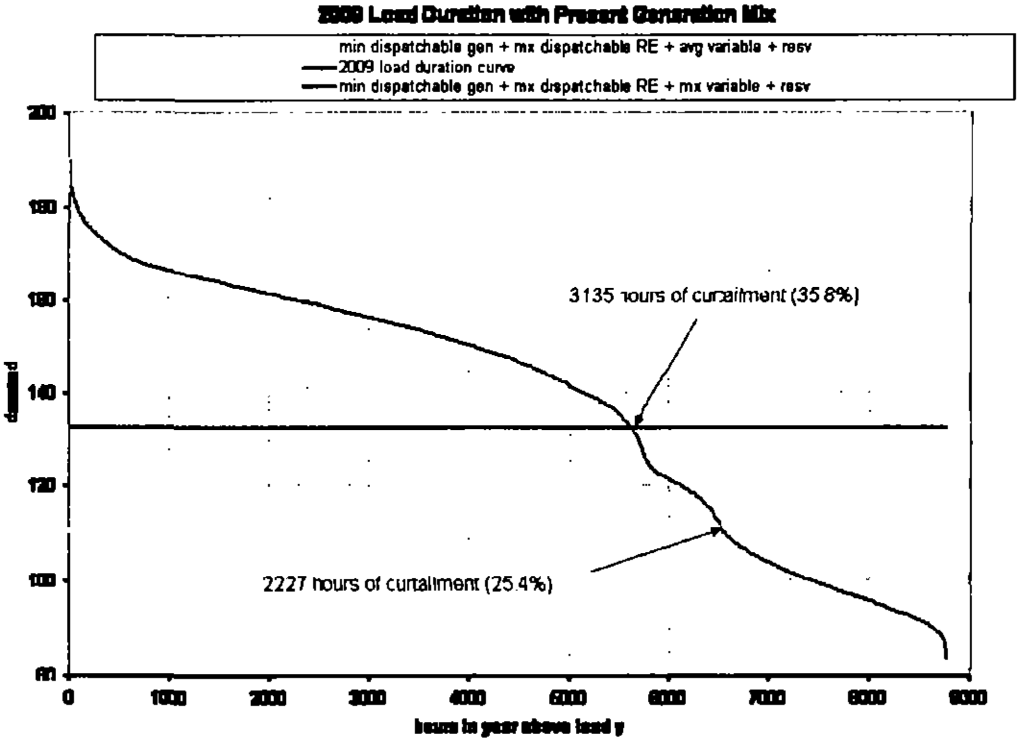



**Figure 3 2009 Load duration curve illustrating a range of possible hours of curtailment due to excess energy based on average and maximum variable generation and typical must-run generation levels**

Figure 3 is for illustrative purposes, as it assumes the typical minimum must-take generation (including reserves) and maximum dispatchable renewable energy. This does not consider periods where must-run generation and/or dispatchable renewable energy are higher or lower due to operating conditions, derations, or outages. The average variable generation and maximum variable generation are used to illustrate the range of curtailment. The actual curtailments will depend on the correlation of high-production, high capacity factor periods. When the resources are correlated in high output, the curtailment extends into more hours of the day (into higher demand periods). High variable production is indeed often correlated for the Hawaii Island wind and hydro resources, as for both types of resources low-production periods correspond to Kona wind conditions and high production periods and high production periods are associated with rainy trade-wind weather. Therefore actual hours of curtailment hours would be greater than indicated by the yellow (average) variable production but less than indicated by the dark blue (maximum) variable production. It is clear the number of hours of curtailment is significant, easily between twenty and thirty percent of the time, there is more energy being produced than the HELCO system can take. The obvious implication of curtailment is that variable renewable energy which was available could not be utilized on the system.

Figure 4 is for the Maui system with similar assumptions as the Figure 3 for HELCO. Since curtailment for excess energy typically happens at in the early morning, the minimum dispatchable generation is representative of typical early morning conditions.

The output for Makila Hydro, a 500 kW hydroelectric unit, is ignored. For Maui curtailment can be from approximately 6 to 24 % of the time. Similar for Maui as it is for HELCO, variable generation that was available could not be utilized on the system.

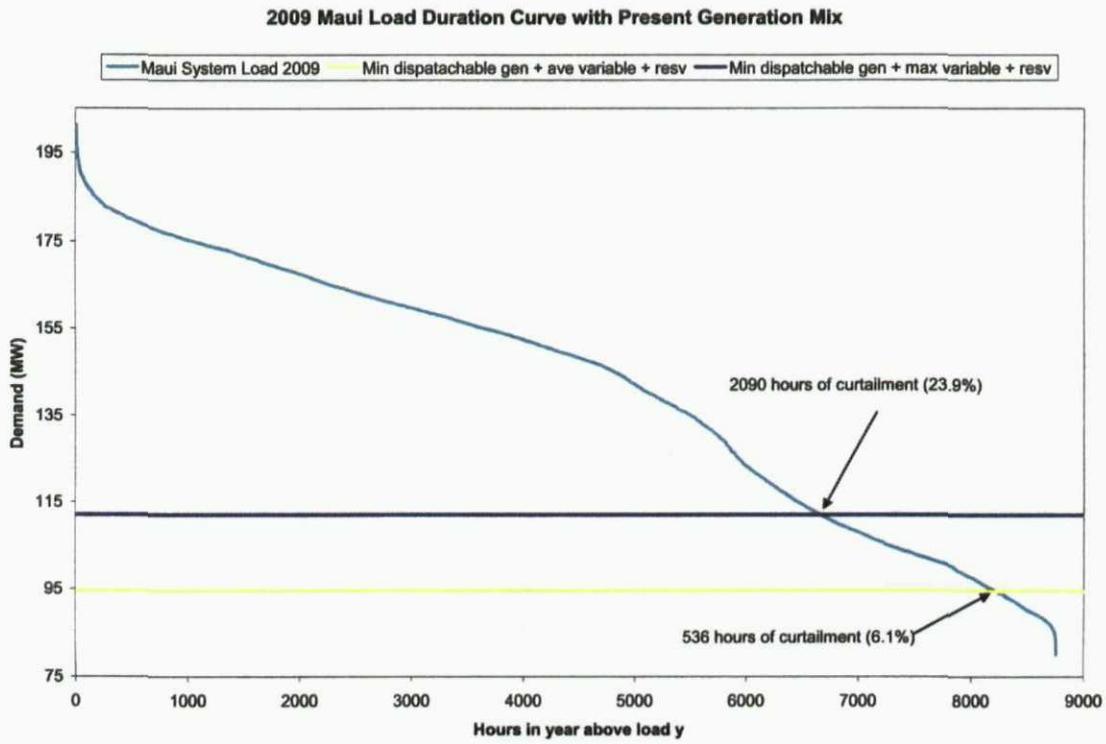



**Figure 4 2009 Load duration curve illustrating a range of possible hours of curtailment due to excess energy based on average and maximum variable generation and typical must-run generation levels**

There are additional implications of operating in a curtailment mode as the dispatchable units are operating at near-minimum dispatchable load (a bit above the minimum load to provide the regulating reserve down). These two areas of impacts are on generator efficiency, which may affect costs; and system frequency response capability, which may affect reliability.

There is a significant negative impact on efficiency when running near minimum output on dispatchable units, and consequently, there may be a negative impact on cost. The efficiency of units at near minimum load is significantly worse than at near maximum loads. This difference is nonlinear, so that near minimum load the efficiency can be magnitude difference. For example, for each kWh at minimum output, the Keahole combined cycle unit uses 158% of the fuel for each kWh at maximum output. The economic impact of this depends on the cost of the must-take energy. In order for the impact to be neutral, the cost of the must-take energy has to be low enough to compensate for the increase in the costs of production incurred by operating must-run generation at less efficient levels.

There is a potential reliability risk operating near minimum output on dispatchable units. The minimum dispatchable output for each dispatchable unit is determined by the lowest level of stable operation on the generating unit. Operating below this level can result in the unit tripping offline or cause deviations from environmental permit requirements. When all units are near the minimum output, the system is vulnerable to failure for loss-of-load events. The ability of the units to back down for high frequency excursions is limited and the units may be driven offline. The present regulating reserve down requirement has been set at the minimum regulating reserve down for the single contingency loss of load during minimum load (off-peak) conditions. Loss of more than this amount (6 MW on the MECO system, 9 MW on the HELCO system) can drive the responsive units (through their droop response) to below their stable operating point and risk loss of the units, or prolonged high-frequency excursions which may cause trips of other generation and cascading outages. The potential loss of load is larger during daytime conditions. The risks of prolonged operation near minimum loads, and possible adjustment to prudent regulating reserve down, need to be studied, and operating criteria revised if necessary, considering the future increase of hours under excess energy conditions.

**Excess Energy with Anticipated Generation Additions**

Both HELCO and MECO have preliminary agreements and/or firm agreements in place for renewable energy additions. The following diagrams illustrate demand vs. available generation for the HELCO future generation scenario. This diagram assumes the minimum must-run dispatchable generation, plus reserves; maximum output from dispatchable renewable energy sources including additional biomass and geothermal planned to be in place by 2012; and maximum variable generation output (wind and hydro). The graphs assume Shipman does not need to be kept in hot-standby due to the response characteristics of the geothermal and/or biomass facilities. This assumption would require confirmation through study.

Attachment 4

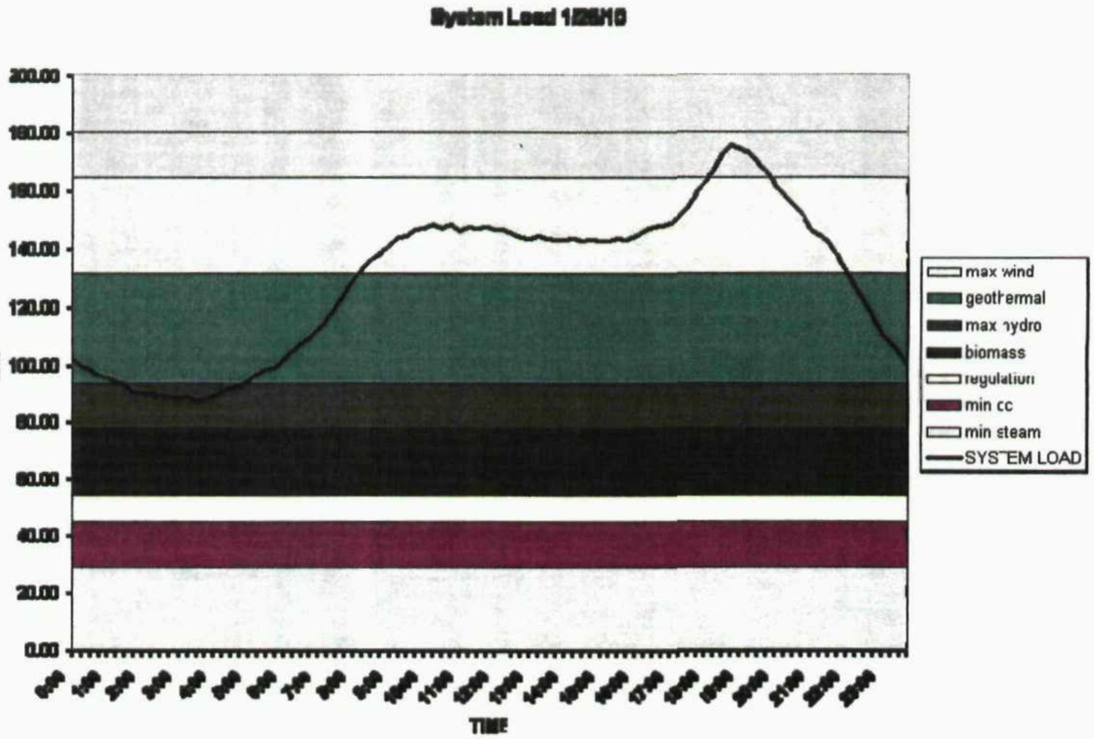



**Figure 5 Present day HELCO net-to-system load curve plotted over 24 hours, plotted against the minimum conventional generation (plus present minimum reserve down) and maximum possible renewable energy. The shaded areas above the dark line indicate periods of excess energy.**

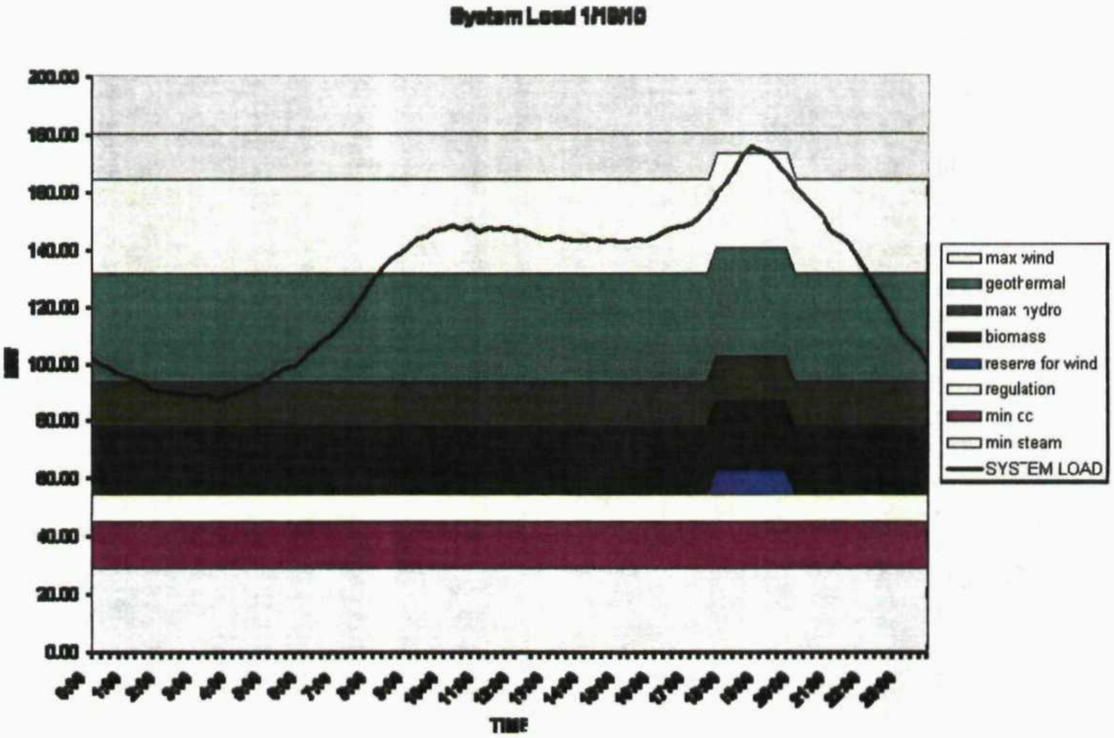



**Figure 6 this graph is essentially the same as the previous graph for HELCO, except an additional unit is brought online during the peak period to provide online reserves as hedge against changes in the wind output.**

The additional renewable energy consists of geothermal and biomass. These dispatchable RE facilities are anticipated to be online in the next two to three years.

This output is shown in a stack chart against a typical daily load curve, arbitrarily selected as a recent Sunday. The first graph assumes that HELCO can operate for that level of variable wind output with the capacity provided by the firm dispatchable units (159 MW). The second graph illustrates the additional curtailments that would be necessary if it is necessary to start up additional generation during the higher peak periods to provide online reserves to cover for the wind uncertainties. The stack areas that are above the load line show periods where there would be excess energy, requiring curtailment of renewable energy from new or existing renewable energy facilities. The geothermal and biomass, will be dispatchable and therefore the capacity will be available on demand to the system except during outages and derations. This graph shows that during high variable output, in the absence of significant load growth the HELCO system can not accommodate all future and existing RE even if all dispatchable conventional generation operates nearly twenty four hours at near minimum output. As mentioned above, operating in that manner could have significant cost implications and may not be prudent due to potential reliability implications. The operating policy for minimum regulating reserve down will need to be reassessed to consider daytime probable load loss events, and the spinning reserve policy may also require reassessment for the future generation mix. Even under periods of moderate variable output, curtailments in the near term seem likely to extend into daytime hours.

Figure 7 illustrates the demand versus available generation for the Maui future generation scenario. Figure 7 assumptions include: 1) regulating reserve up to cover 50% of the first 30 MW of wind and 100% of any additional wind generation, 2) regulating reserve down is fixed at 6 MW, 3) two additional wind farms of 21 MW each, 4) unit start times and loading schedule are ignored, 5) output from Makila Hydro (500 kW) is ignored. Other than the 2 wind farms, all other potential renewable energy generation is ignored.

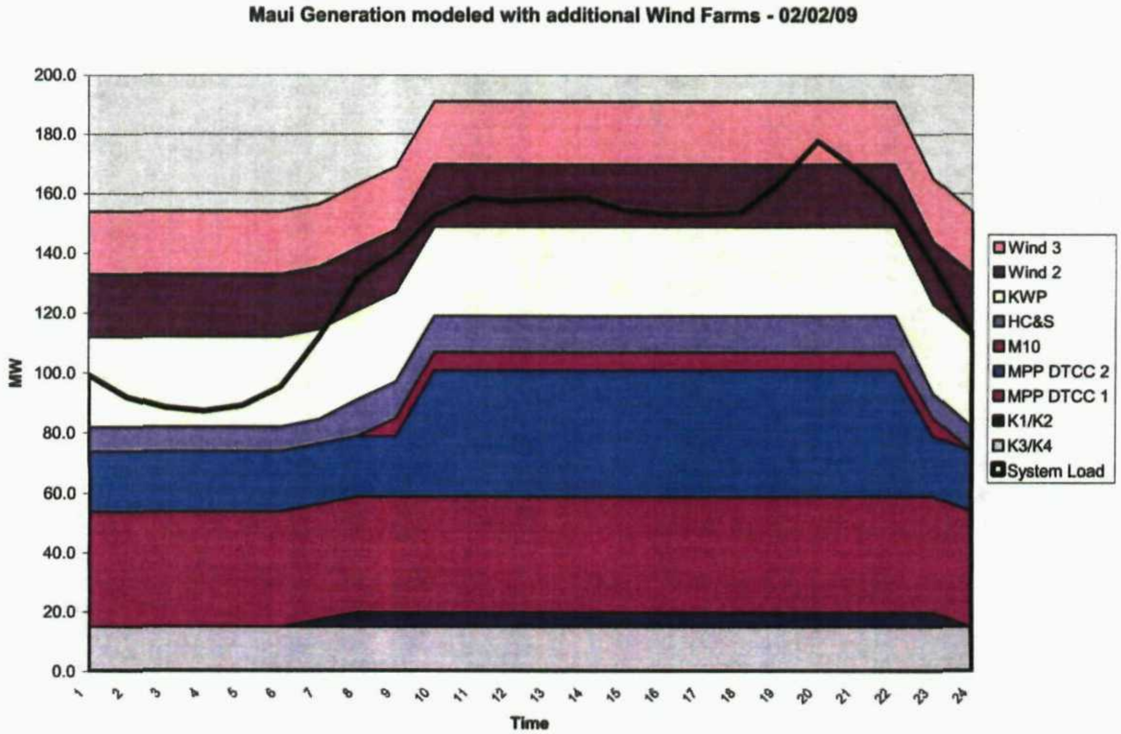



Figure 7 Present day load curve plotted over 24 hours, plotted against the minimum conventional generation (plus regulating reserves) and maximum possible renewable energy for Maui. The shaded areas above the dark line indicate periods of excess energy.

Figure 7 shows a typical daily load profile and against the minimum output from the dispatachable generation (including regulating reserves, must run, and must take) and maximum variable generation. The stack areas above the System Load line represent excess energy and would require curtailment. Similar to HELCO, absent significant load growth, MECO cannot accommodate all the existing or future renewable generation even with conventional generation backed down to minimum (plus down reserve) 24 hours a day.

The stack chart provides a useful understanding of the dispatch profile for a 24 hour period as compared to demand, and illustrating the hourly curtailments. Another manner of looking at the scenario over an annual period is to compare the impact of the anticipated dispatchable RE generation additions on the 2009 load duration curve, as was done in Figure 3 and 4 considering present RE generation.

Attachment 4

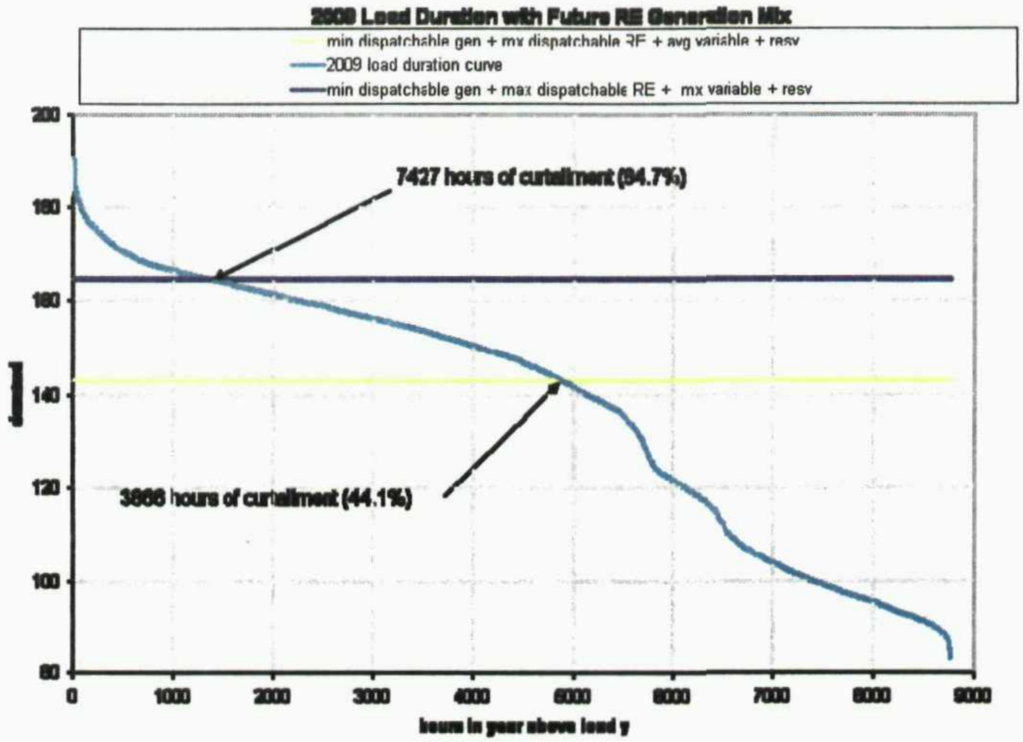



**Figure 8 Load Duration Curve showing potential curtailment hours for annual average variable generation, and maximum variable generation, with minimum dispatchable must-run conventional generation and maximum dispatchable RE generation including anticipated RE additions for HELCO.**

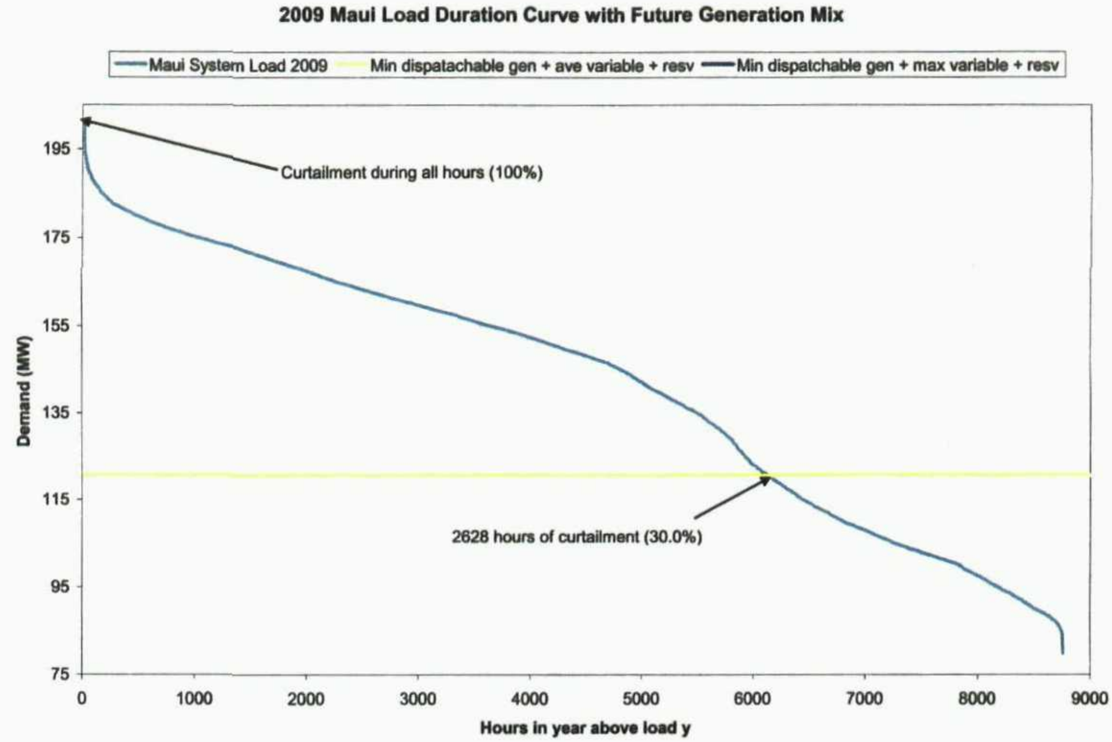



**Figure 9 Load Duration Curve showing potential curtailment hours for average future variable generation, and maximum future variable generation, with minimum dispatchable must-run conventional generation.**

As can be seen by these graphs, in the absence of load growth, renewable energy curtailments will be much more significant. Depending on the correlation of the variable generation production, the curtailments can range from 30 to 100 percent of the hours in a year. Under maximum variable energy production, there would be very little to no demand to serve. Figure 8 has the same assumptions as the present day graph (Figure 3), and illustrates maximizing RE by operating at minimum load with existing reserve policies, and does not consider outage periods or special operating conditions. Figure 9 varies from the present day graph (Figure 4) by assuming that the generation would be typical of daytime conditions, and that there is enough regulating reserve up to cover 50% of the first 30 MW of wind and 100% of each MW of wind above 30 MW. As mentioned above, an assessment should be performed to reevaluate operational requirements for must-run units and reserves considering the future generation mix.

**Impact of Distributed Generation (such as FIT and NEM)**

The impact of distributed generation will be to reduce the system demand served by the transmission generation resources. Most of these resources at present are relatively small, and not visible or controllable by the system operator.

The system demand declined in 2009 as compared to 2008 (although for MECO the 2009 peak was higher than the 2008 peak.) Some of the decline is undoubtedly due to the effect of the large number of distributed generation resources added in 2009. As of

12/31/2009, there is 6.8 MW of variable (mostly PV) distributed resources and 2.3 MW of firm distributed resources interconnected with the HELCO system. These consist of NEM, No-sale, and Schedule Q resources. As of 12/31/09, there is 4.1 MW of variable (mostly PV) distributed resources and 1.2 MW of firm (combined heat and power units) distributed resources interconnected with the Maui System. These consist of NEM and No-sale resources. As these resources are not separately metered, it is uncertain what the actual production from these was in 2008. We are presently undertaking projects to help determine the capacity factors and variability of these resources to facilitate improved load forecasting and system planning. It is clear when comparing the 2008 and 2009 curves that the largest difference is in the daytime load range, rather than off-peak and evening peak loads, which gives weight to the possibility that there was a significant impact of distributed PV.

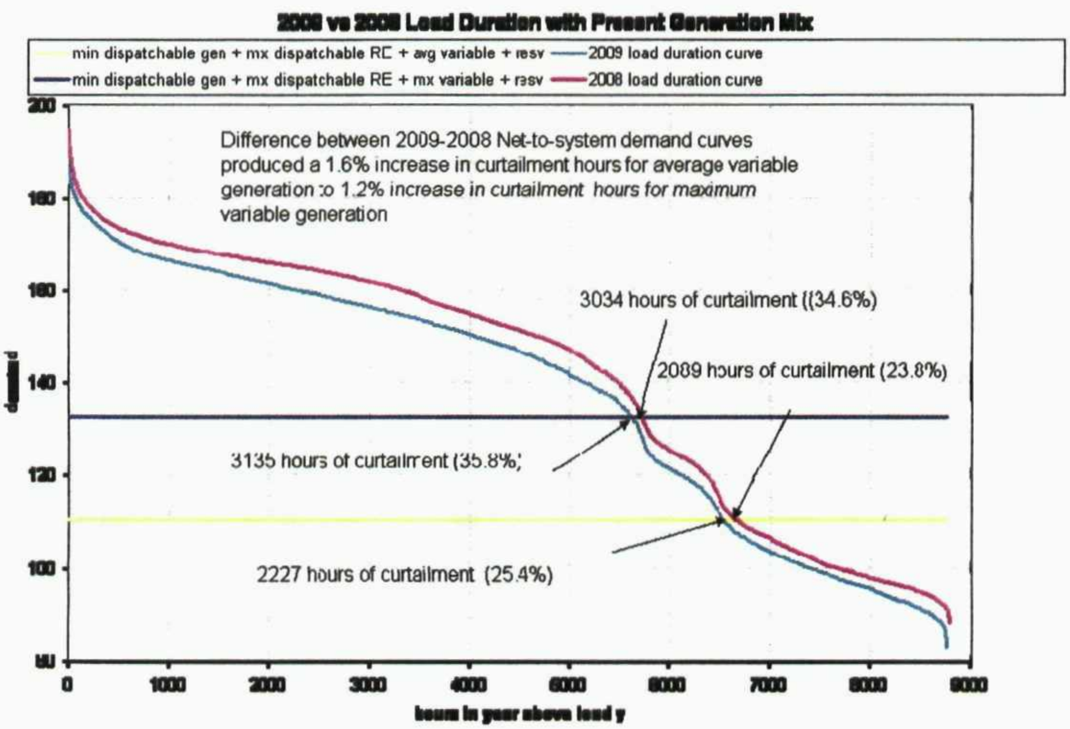



**Figure 10 Comparison of curtailment analysis for the same generation assumptions applied to the 2008 and 2009 load duration curves for HELCO.**

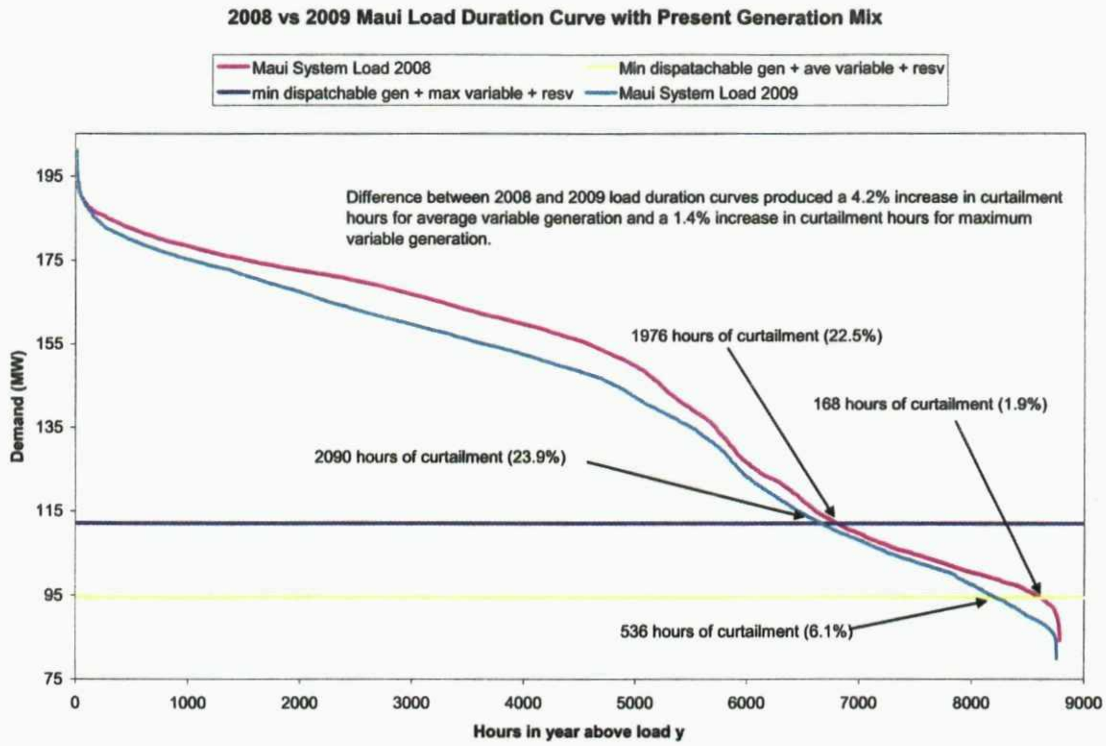



**Figure 11 Comparison of curtailment analysis for the same generation assumptions applied to the 2008 and 2009 load duration curves for Maui.**

The difference between the 2008 load duration curve and 2009 load duration curves, with all other factors being equal, would result in additional curtailment hours in 2009 as compared to 2008. Since the change in the load duration curves appears to be primarily during typical daytime load periods, the impact is much more significant in consideration of the possible curtailments of future load resources. This is illustrated in the graph below.

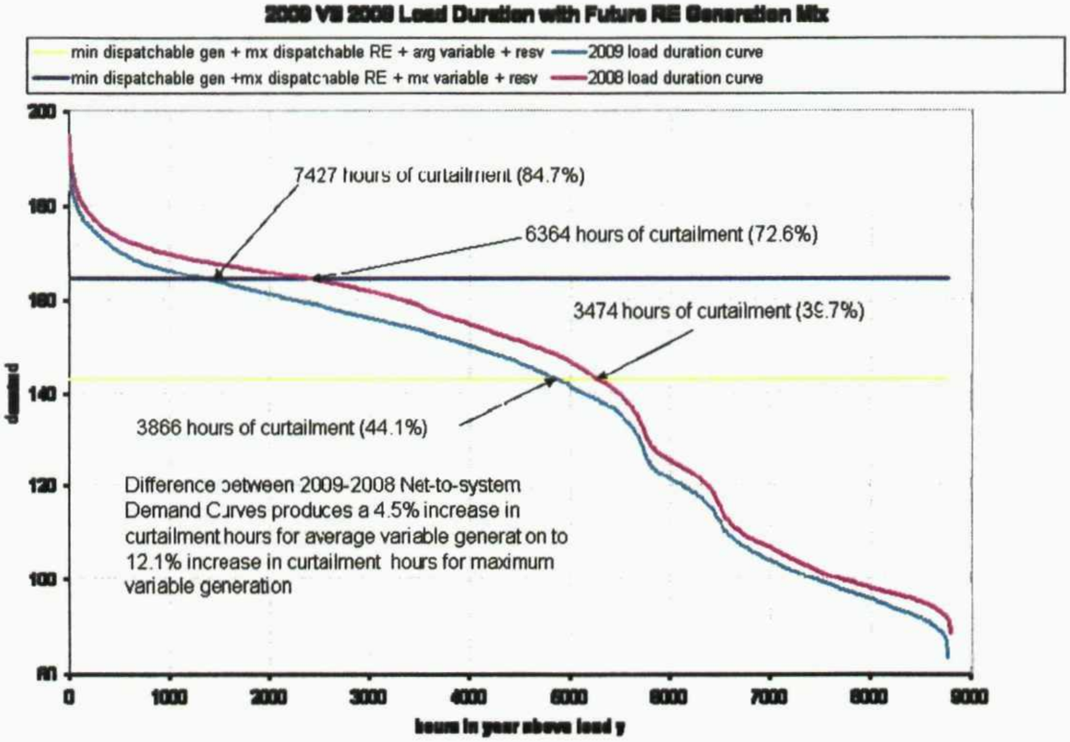



**Figure 12 A comparison of a curtailment analysis for future RE additions on the HELCO system utilizing 2008 and 2009 load duration curves.**

Figure 12 illustrates that with the anticipated RE additions, even a relatively small reduction in the load during the mid-range of the load-duration curve can dramatically reduce the ability of the HELCO system to accept the existing and anticipated RE energy. The curtailment hours were increased between by 4.5% and 12.1% for the average and maximum variable RE cases.

There is nearly 8.0 MW of additional distributed PV planned to be installed on the HELCO system in 2010. This is a larger increase in distributed PV than occurred in 2009. It is therefore anticipated that the load duration curve for 2010 will be below that of 2009 and the decline in demand during 2010 is expected to similarly be larger in daytime load periods than during peak and minimum load periods.

The equivalent graph for Maui is shown below (Figure 13). Although curtailment hours were increased by 2.3 %for the average variable generation case, no increase is possible for the maximum variable generation case.

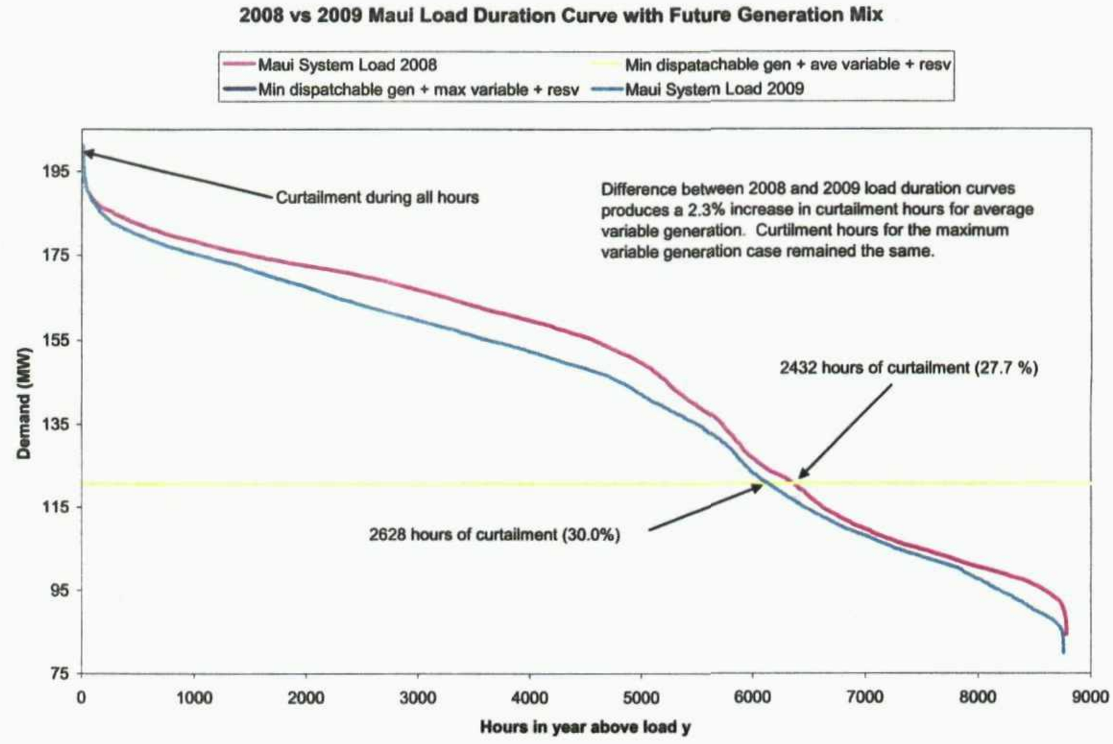



Figure 13 A comparison of a curtailment analysis for future RE additions on the MECO system utilizing 2008 and 2009 load duration curves.

It is known that the distributed PV is variable, but the degree of variability and its correlation across each island system is not known. The variability of these resources may require an increase in online reserves, which in turn, may require additional must-run dispatchable generation and increased curtailments of variable RE.

## Conclusion

The HELCO and MECO systems have a large amount of renewable energy production from existing renewable energy providers. Under present conditions, there are many periods where the renewable energy must be curtailed due to excess energy. HELCO has formal agreements in place to procure additional RE in the next two to three years, consisting of 8 MW of geothermal and approximately 24 MW of biomass energy. These resources will be dispatchable and the energy therefore available on demand except during outages and derations. The number of hours of curtailments will be increased. MECO is in negotiation for additional variable renewable energy resources from wind. As this additional energy is variable, the production levels are uncertain; but under various conditions curtailments will occur throughout the entire day.

The addition of distributed energy resources will result in reduced ability to accept renewable energy from the new and anticipated resources. This has an effect on the amount of energy purchased from the new and existing resources, and may also affect the commercial viability of the anticipated resources. The reduction in demand between 2009 and 2008 has a significant impact on the ability to accept energy from new and anticipated resources, in the analysis above as illustrated for HELCO the decline resulted in a 4% to 12% reduction in the number of hours the energy could be accepted under an average and maximum variable generation assumption. Similarly, MECO transmission providers who are curtailing potentially throughout the entire daytime load periods will experience reduced sales. The decline in demand in 2010 is anticipated to be greater than 2009 due to the impact of an additional 7.95 MW of distributed PV by the end of this year at HELCO

As illustrated above, the addition of distributed generation resources has already increased the curtailment of existing RE resources but, as the renewable energy is increased such that curtailment may go into the day time hours, this impact will be magnified with new resources. The projected purchases for the anticipated RE will be reduced by the distributed generation resources, in the near term, the decrease might be extremely significant.

The system benefits of distributed PV differ from the cost and reliability benefits of the anticipated dispatchable RE. Dispatchable RE resources provide firm capacity and grid management. Costs can also differ.

The HELCO system will operate under extended periods with a minimal amount of dispatchable generation online. This will have an effect on the efficiency of the generation and the response capabilities for frequency control. MECO has similar concerns and must make additional decisions regarding minimum conventional generation, to cover for variability, as unlike HELCO the renewable energy additions are all variable. A comparison of the HELCO and MECO stack charts with consideration for anticipated resources illustrates how a larger percentage of renewable energy can be achieved when the renewable energy resources include firm dispatchable sources which can displace conventional units due to their contribution to grid management.

Increasing the renewable energy percentage above that already in place for the HELCO and MECO systems, which are anticipated to be very high, can occur only if demand is increased or if RE is added to the system which can reduce the number of must-run units. The addition of biomass and geothermal is expected to provide such benefits, and the analysis above reflects a minimal amount of conventional generation assuming that those benefits and capabilities are realized. Any further changes in generation mix will require an evaluation of costs and necessary unit characteristics.

**Recommendations**

- Additional mechanisms to promote DG in order to increase renewable energy (RE) are not recommended for the HELCO and MECO as these resources will result in significant decrease in the ability to purchase RE from existing and anticipated RE resources. The existing and near-term DG may affect the commercial viability of anticipated RE additions as purchases may be less than prior studies indicated for the anticipated additions.

- The capacity factor and variability of the existing and planned variable DG should be determined and incorporated into planning and operational time frames. Of particular importance are the impact upon the load forecast and load duration curve, and the impact upon frequency control and regulation.
- The operating criteria for frequency control and load following (reserves, ramping capability, etc) needs to be evaluated for the future operating conditions, to consider extended hours of curtailment periods (units operating at near minimum loads) and impact of the distributed variable generation.
- Analysis should be performed to understand the cost impacts of operating at very low efficiencies, to accept existing and anticipated RE resources, with consideration of the reduction in load from existing and planned DG. This cost consideration should consider the sensitivity to changes in fossil fuel prices.

Attachment 5

# DISTRIBUTION GENERATION (DG) RELIABILITY STANDARDS DEVELOPMENT PROCESS

# FEED IN TARIFF DOCKET NO. 2008-0273PROPOSAL

## LANAI ANALYSIS

February 8, 2010

Prepared By:
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**LANAI DISTRIBUTION GENERATION RELIABILITY STANDARDS**

## INTRODUCTION

Maui Electric Company (MECO) provides electrical service to the islands of Maui, Lanai and Molokai. This study focuses on the island of Lanai.

Lanai has three 12 kV distribution circuits serving the entire island load. One circuit has 1,207 kW of Photovoltaic (PV) and 830 kW of generation Combined Heat and Power ("CHP"). Currently, 1,200 kW of the 1,207 kW of PV installed on Lanai comes from the Lanai Sustainability Research (LSR) facility. The LSR PV system is presently operating at 600 kW until an energy storage device, such as a battery system. Since the full 1,200 kW of the solar facility has not been utilized, there is insufficient history and actual operation to determine how the system will respond to the existing 600 KW and high penetrations of PV. The other two circuits do not presently have any significant renewable resources installed. A detailed IRS was conducted because of the large system and circuit penetration level that was caused by this facility. A PV penetration at this level can create reliability and stability issues, if not adequately studied.

At Miki Basin (the MECO generating station on Lanai), there are two 2,200 kW diesel generators (LL7 and LL8) and six smaller 1,000 kW generators (LL1–6). Historically, LL7 and LL8 were on-line all of time except for maintenance or forced outage and provided the majority of the base load power and dispatch to serve the variability in the customer load.

The 830 kW CHP generator is connected to the distribution system to serve the Manele Bay Hotel. The CHP operates as a base load and potentially replaces one of the 2,200 kW Lanai generators (either LL7 or LL8) during minimum load periods. The CHP generator recently became operational so there is insufficient operating history to determine the flexibility and reliability of the generator.

With all of these recent changes to the Lanai distribution system, Lanai needs to evaluate the potential distributed generation that can be incrementally added to the system. This report briefly summarizes the issues and potential problems that must be studied before the addition of more renewable generation, whether these are dispatchable or must run.

## CONCLUSIONS

The Maui and Hawaii Electric Light Company (HELCO), which serves the island of Hawaii, systems, are already experiencing renewable resource curtailments, under frequency, stability and other reliability issues. Given the problems at the other two islands, Lanai needs to study their systems to avoid similar problems.

One of the three distribution circuits on Lanai has 1,207 kW of PV and an 830 kW CHP generator. The other two circuits do not have any significant renewable resources. Adding generation to any of the circuits needs to be evaluated carefully at this point due to the large existing penetration of variable distribted generation (DG) on the island and the fact that the two low DG percentage circuit loads are used for the underfrequency load shed scheme for the island.

As stated previously, historically Lanai has had the two large 2,200 kW generators connected to the system at all times. However, with the addition of the CHP, one generator is now cycled daily during minimum load periods.

The preliminary analysis completed in this study demonstrates the potential for renewable resource curtailments during the on-peak periods. This is especially significant during the light load periods such as April when customer usage is low but solar generation is high.

All of the islands are recommending that the under frequency relay setting for the renewable resources be reduced to 57 Hz to allow the renewable resources to remain on line longer during emergency conditions. This may need to be lower for the Lanai and Molokai systems, which generally have larger frequency swings than on the other islands. The ride-through requirements for the PV and the CHP facilities extend down to 55 Hz, which is outside the range of IEEE and UL settings.

## DISCUSSION

There are three 12 kV distribution circuits serving the Lanai load. One of the circuits includes the existing 1,207 kW of PV and 830 kW of CHP. This circuit could be the most impacted by variability of PV generation given the amount of existing DG facilities on the circuit. The other two circuits do not have any significant DG resources, but are used for the under frequency load shed scheme for the island.

The 830 kW CHP unit is a recent addition to the Lanai system. It is a must run unit and is generally dispatched at 800 kW during the day. The CHP displaces either LL7 or LL8 during the minimum load period. Both the large generators (LL7 and LL8), even at minimum generation, and the CHP can be on line at the same time. The second large Lanai generator is cycled daily and is off-line from approximately 2200 hours to 800 hours depending on the system load. This creates a potential reliability and stability issue during the off-peak hours. With only one dispatchable generator on-line at night, any outage of the large generator will create an unstable condition since the second generator is off-line. The loss of the CHP is not as critical since the loss of the CHP can be replaced with the excess generating capacity of the large generator. However, these outage conditions have not been studied in detail by Lanai.

In 2009, there was only 623 kW of PV in service. The remaining 600 kW of PV for the LSR facility will begin operation when a battery system has been installed. The battery system will be used to smooth the variability in the PV generation and enable the system to meet the performance requirements. Figure 1 below is a 2009 April minimum load time period except that the full 1,200 kW of the LSR facility is modeled as being in service and generating. As shown, there could be some hours where the LSR facility will be curtailed. The two Lanai generators (Miki) are at their lowest minimum load generation levels to serve the variability in the PV generation and the customer load. The PV facility has a more stringent ramp rate limit for the hours when only one 2,200 kW generating unit is online. The generator's minimum load is 27% of the maximum rating and cannot currently be reduced any further without causing some potential operating problems. Lanai will need to develop some procedures for curtailments during these minimum load hours. (Note that in the figures the Miki basin generation is kept at minimum to show the maximum potential for additional DG. However, in doing so, it appears that the generation does not equal the load at times. In actuality, the Miki Basin units would increase their output to equal the load during these times.)

**Figure 1 April Minimum Load and LSR at 1,200 kW**

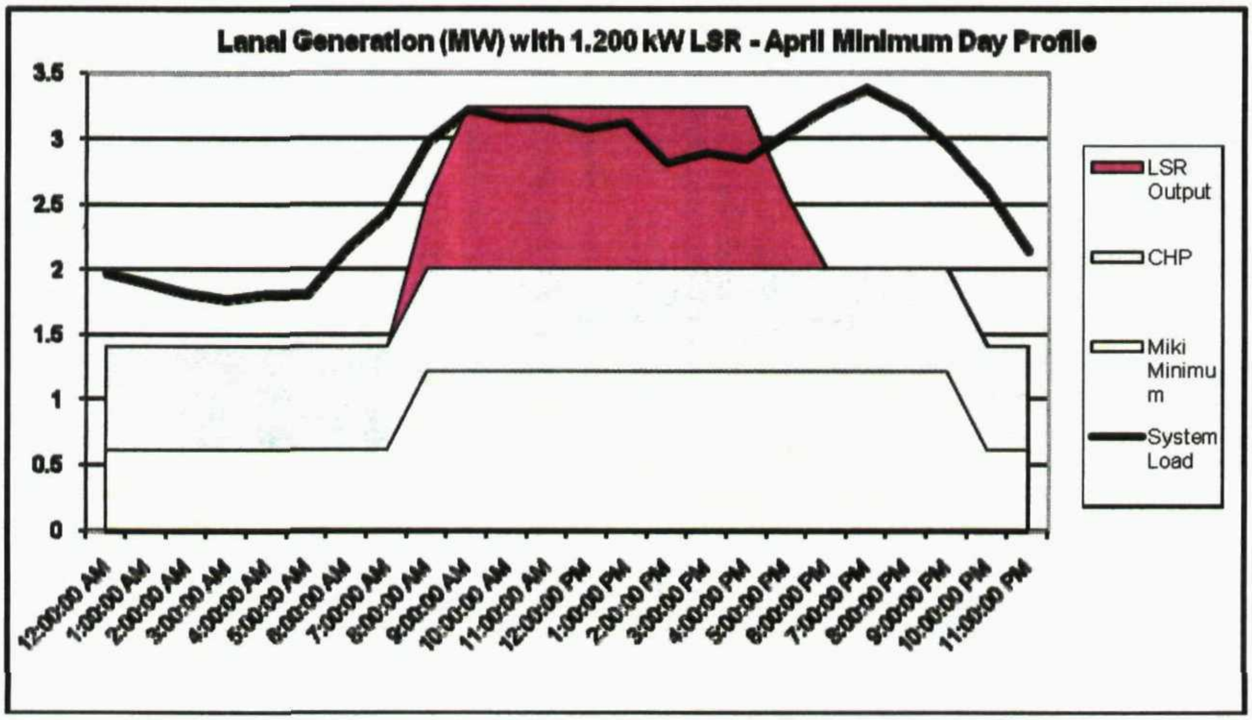
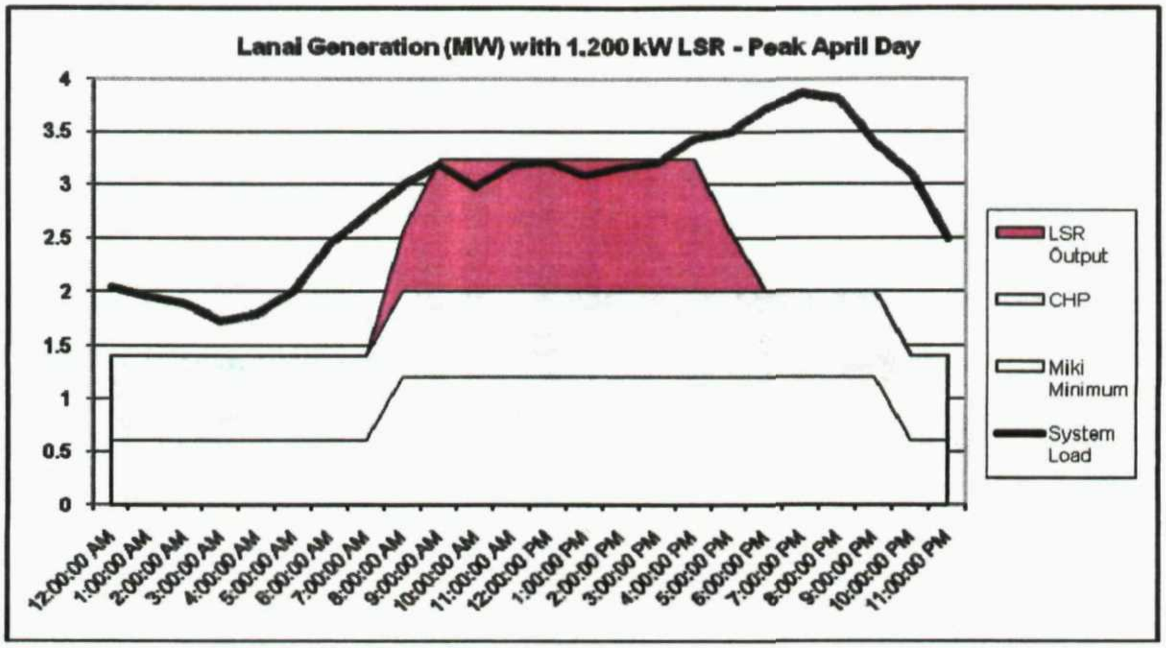



Figure 2 below is a peak day in April. The dispatch is the same except the peak load profile changes. The system load is higher resulting in fewer curtailments hours.

**Figure 2 April Peak Day with 1,200 kW of LSR**




The three figures below show the potential generation dispatch impacts if 3%, 5% and 7% DG are added to the system. For this preliminary analysis, the DG resources are modeled as new PV. As DG resources are added to the system, there are more curtailment hours of the DG and the existing PV. The 3% DG is curtailed the entire April minimum load day as shown in Figure 3. The CHP is assumed to be at 800 kW and Units LL7 and LL8 are at minimum generation. These units cannot be reduced further.

**Figure 3 April Minimum Load with 1,200 kW LSR and 3% DG**

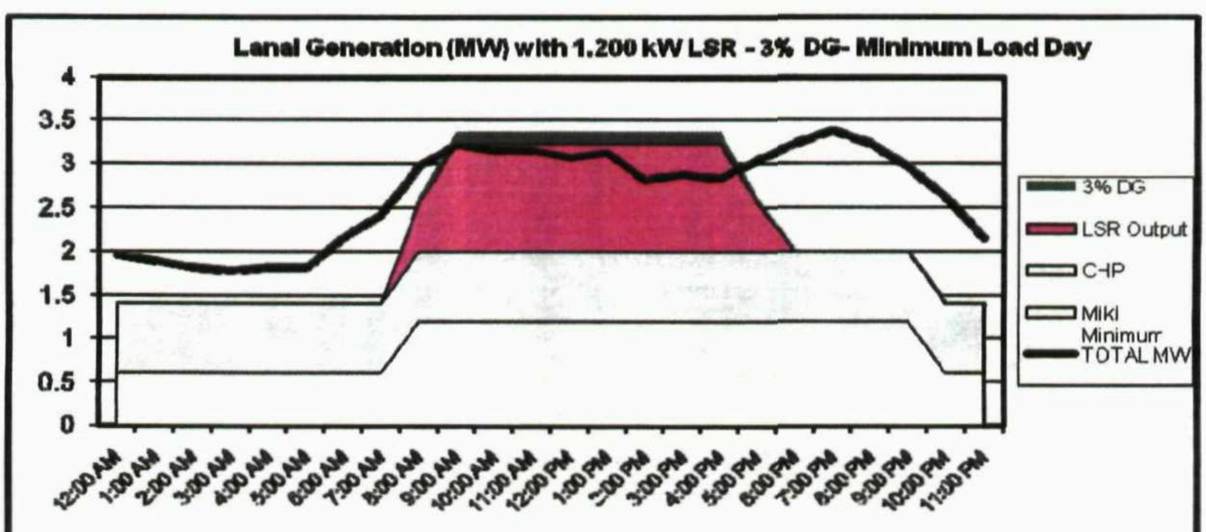


Figure 4 shows the potential curtailment of renewable resources with a 5% DG penetration. The DG and some of the existing 1,200 kW of PV could be potentially curtailed. In fact, it would appear that most of the DG would be curtailed.

**Figure 4 April Minimum Load with 1,200 kW PV and 5% DG**

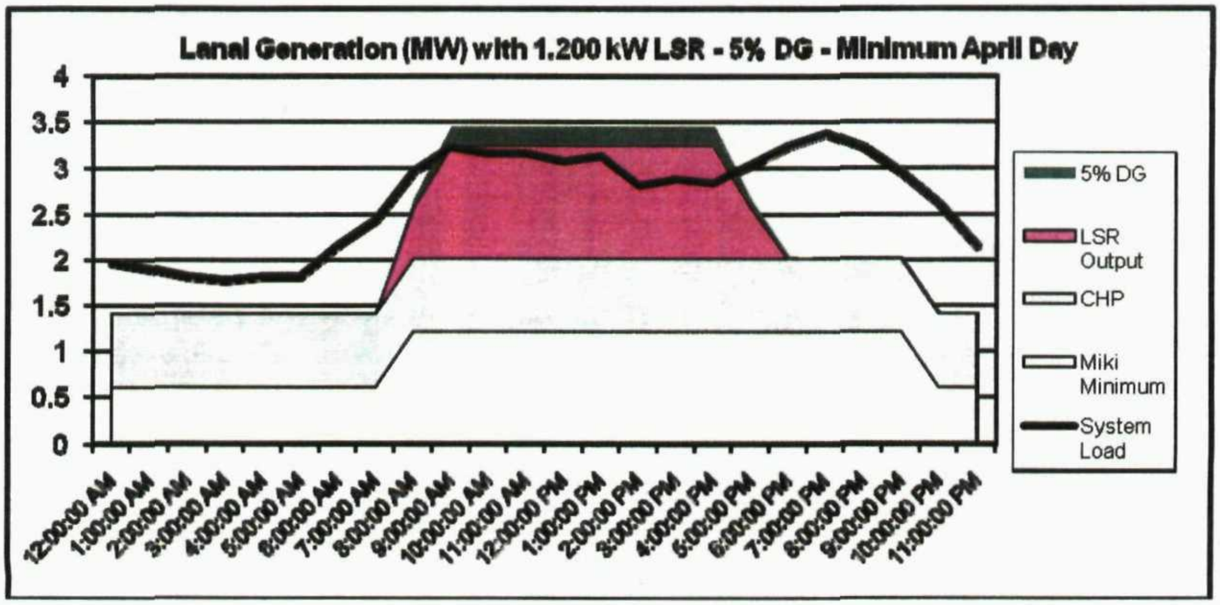
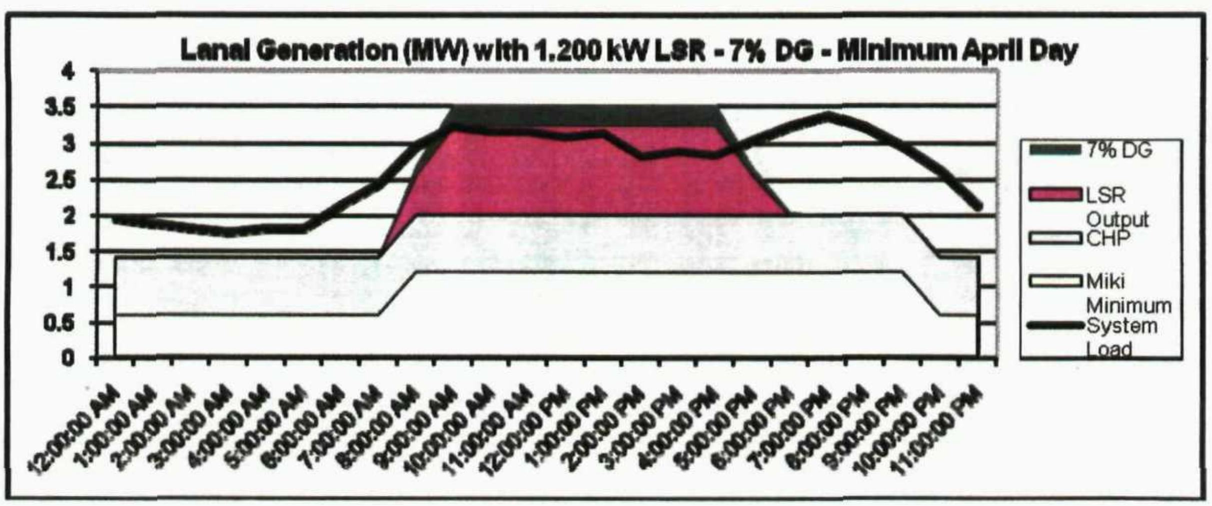



Figure 5 shows the same Apil minimum load day but with 7% DG. As expected, the more PV DG added to the system, the DG curtailment capacities increase.

**Figure 5 April Minimum Load with 1,200 kW LSR – and 7% DG**



Attachment 6

# DISTRIBUTION GENERATION (DG) RELIABILITY STANDARDS DEVELOPMENT PROCESS

# FEED IN TARIFF DOCKET NO. 2008-0273PROPOSAL

## MOLOKAI ANALYSIS

February 8, 2010

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**MOLOKAI DISTRIBUTION GENERATION RELIABILITY STANDARDS**

## INTRODUCTION

Maui Electric Company (MECO) provides electrical service to the islands of Maui, Lanai and Molokai. This report briefly summarizes the generating resources and distribution system on the island of Molokai.

As part of the development of Reliability Standards under the Feed-on-Tariff process, BEW Engineering conducted a series of preliminary assessments of the Hawaiian Electric Companies' island systems. Within the time constraints of this preliminary review process and given the current penetration levels on Molokai, only a cursory review of the baseline system was completed for this island. Discussions and recommendations that follow are based on observations and issues of system reliability impacts on the other islands which should help inform monitoring and proactive planning for the island of Molokai. As new renewable programs such as the FIT are introduced onto the island, system changes should be considered and studied to ensure that whatever resources are added, impacts on system reliability can be understood.

## DISCUSSION

The generating resources and distribution system on the island of Molokai are similar in size and function to the island of Lanai. With comparable loads and types of generating resources, the operations and planning requirements are very similar, Molokai has three 2,200 kW Caterpillar generators and other smaller generators that serve a peak load of approximately 5,900 kW. Two or more of these large generators are on-line continuously (with one operating in isochronous mode) to serve load, set frequency, maintain voltage, provide regulation and spinning reserves. At night, one of the generators can be cycled off, depending on system needs. The Molokai electrical delivery system is comprised of five 12 kV distribution circuits serving the island load.

Today, Molokai has 294 kW of existing DG that creates a DG penetration of 4.9% of the system peak demand. With an additional 139 kW planned DG that the utilities are aware of, this adds 2.3% DG penetration on to the distribution circuits. The projected DG penetration in the near future could rise up to 7.3% or higher.

Given the similarities of the island systems and comparable resources and loads with the island of Lanai, it is recommended that prudent measures be taken on Molokai to begin tracking system level and distribution level impacts of increasing renewables. Currently, the major difference between Lanai and Molokai is the existing level of DG penetration. However, given the incentives for adding renewables and based on projected DG resources planning for the islands, Molokai has the potential for similar excess energy problems during low peak loading conditions and minimum load as the island of Lanai and the other Hawaiian utilities with increasing renewable DG resources such as PV.

## RECOMMENDATIONS

The Maui Electric Company (MECO) and Hawaii Electric Light Company (HELCO), which provides electrical services for the islands of Maui, Molokai, Lanai and the Big Island of Hawaii systems, are currently experiencing renewable resource curtailments, under frequency, stability and other system reliability issues with existing levels of renewable energy penetration. Given the system-level problems currently observed on the other two islands serviced by MECO, prudent system level limits and studies should also be considered to minimize high penetration, variable renewable impacts on Molokai.

An example of such proactive measures being taken is the resetting of the under frequency relay limits from 59.3 Hz to 57 Hz to allow the DG to remain on line longer during emergency conditions. For Lanai and Molokai, these settings may need to consider accommodating larger frequency swings than on the other islands. These require additional dynamic analysis for the distribution circuits. Generators on the HECO and HELCO systems, as well as those on MECO's Maui system, operate under droop control, where the combined inertias of the individual generating units are utilized to resist changes in system frequency during disturbances. Any post-disturbance frequency deviation is then eliminated through Automatic Generation Control (AGC) action on certain generators' turbine governors. The Lanai and Molokai systems, in contrast, do not have a sufficient number of generators nor combined inertia to utilize droop control with AGC, and rely instead on a single generating unit, operating under isochronous control, to regulate system frequency. This type of operation is lacking in inertial response, making it subject to greater swings in frequency (or poorer transient stability) following system disturbances.

BEW recommends that prudent measures be taken to curb reliability impacts on Molokai by establishing some system limit guidelines and by conducting detailed analysis of existing system data similar to the HELCO and HECO grids to determine the exact system studies that should be completed as DG penetrations continue to increase.

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(Docket No. 2008-0273)

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